

Continuous Emissions Monitoring System

Monitoring Plan for the

Y-12 Steam Plant

ORIS Number 880055

Y-12 National Security Complex

Oak Ridge, Tennessee

managed by
BWXT Y-12, L.L.C.
for the
U. S. Department of Energy
Contract DE-AC05-00OR22800

Prepared by

The logo for URS, consisting of the letters 'URS' in a bold, black, sans-serif font.

URS Group, Inc.
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February 2003
Client Subcontract No. 4300019834
URS Project No. 809930

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REVISION LOG

REV.	DATE	DESCRIPTION	CHECKED	APPROVED
A	01/31/03	Draft for Client Review	JC	01/31/03
B	02/14/03	Revised with BWXT comments	JC	02/17/03

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ACRONYMS

AAR	Authorized Account Representative
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO ₂	Carbon Dioxide
DAHS	Data Acquisition and Handling System
EDR	Electronic Data Report
EGU	Electrical Generating Unit
EPA	U.S. Environmental Protection Agency
EPA-CAMD	EPA's Clean Air Markets Division
ESC	Environmental Systems Corporation
GCV	Gross Calorific Value
LED	Light Emitting Diode
MDC	Monitor Data Checking
MER	Mass Emission Rate
MPC	Maximum Potential Concentration
NO ₂	Nitrogen Dioxide
NO	Nitrogen Oxide
NO _x	Nitrogen Oxides
ppm	parts per million
QA	Quality Assurance
QC	Quality Control
RATA	Relative Accuracy Test Audit
SIP	State Implementation Plan
TDEC	Tennessee Department of Environment and Conservation
URS	URS Group, Inc.
Y-12	Y-12 National Security Complex

1. INTRODUCTION

1.1 GENERAL

The Oak Ridge Y-12 National Security Complex (Y-12), managed by BWXT, is submitting this Continuous Emissions Monitoring System (CEMS) Monitoring Plan in conformance with the requirements of Title 40 of the U.S. Code of Federal Regulations (CFR) Part 75. The state of Tennessee identified the Y-12 Steam Plant in Oak Ridge, Tennessee, as a non-electrical generation unit (EGU) nitrogen oxides (NO_x) budget source as a result of the NO_x State Implementation Plan (SIP) under the Tennessee Department of Environment and Conservation (TDEC) Rule 1200-3-27.

Following this introduction, the monitoring plan contains the following sections: CEMS details, NO_x emissions, and quality assurance (QA)/quality control (QC). The following information is included in the attachments: fuel and flue gas diagram, system layout, data flow diagrams, Electronic Monitoring Plan printouts, vendor information on coal and natural gas feed systems, and the Certification Test Protocol.

The Y-12 Steam Plant consists of four Wickes boilers. Each is rated at a maximum heat input capacity of 296.8 MMBtu/hour or 250,000 lb/hour of 250-psig steam. Although pulverized coal is the principal fuel, each of the units can fire natural gas or a combination of coal and gas. Each unit is equipped with a Joy Manufacturing Company reverse air baghouse to control particulate emissions. Flue gases travel out of the baghouse, through an induced draft fan, then to one of two stacks. Boilers 1 and 2 exhaust through Stack 1. Boilers 3 and 4 exhaust through Stack 2.

A dedicated CEMS will be installed in the ductwork of each boiler, downstream of the baghouse. The CEMS will be designed, built, installed, and started up by URS Group, Inc. (URS). Data acquisition and handling will be accomplished using a data acquisition and handling system (DAHS) designed, built, and programmed by Environmental Systems Corporation (ESC).

The installed CEMS will continuously monitor NO_x, flue gas flowrate, and carbon dioxide (CO₂). The CEMS will be utilized to report emissions from each unit for each ozone season starting May 1, 2003.

Each boiler has independent coal and natural gas metering systems. Coal is fed to each boiler by belt-type coal feeders. Each boiler has two dedicated coal feeders. Natural gas may be burned along with coal for flame stability. The boilers may also be fired on natural gas alone. Orifice meters measure the natural gas flow to each boiler.

Attachment 1 is a schematic diagram of one boiler showing the fuel and flue gas systems. The locations of the CEMS sampling point and flow monitors are shown in Attachment 2. As shown in Attachment 2, these locations meet the requirements specified in 40 CFR 75, Appendix A; 40 CFR 60, Appendix A, Method 1; and 40 CFR, 60, Appendix B, Performance Specification 1. The locations of the sampling ports where the reference method tests will be performed are also shown.

The various federal and state unit identification and permit numbers are listed in Table 1.1.

Table 1.1. Permit numbers

Federal or state identification	Number
ORIS Number	880055
Plant ID	01-1020
Tennessee Operating Permit	034809F
Unit Designations	
• Boiler 1	31
• Boiler 2	32
• Boiler 3	33
• Boiler 4	34

The facility location and stack base elevation are identified in Table 1.2.

Table 1.2. Facility location

Latitude	35° 58' 56" N
Longitude	84° 15' 41" W
Elevation at Stack Base	966 ft above mean sea level

1.2 OTHER EMISSIONS MONITORING

Opacity is currently monitored in each stack. The requirement for opacity monitoring is not required by the NO_x SIP program (TDEC Rule 1200-3-27) but as a condition of the Tennessee operating permit. The existing opacity monitors will be replaced by new units at the location of the existing monitors. The new opacity monitors will meet the requirements of 40 CFR 60, Appendix B and TDEC Rule 1200-3-10. Opacity will be monitored year-around.

2. CONTINUOUS EMISSIONS MONITORING SYSTEMS DETAILS

The primary components of the CEMS are the sampling probes, flue gas flow monitors, NO_x and CO₂ analyzers, and a DAHS. These are described in this section.

2.1 CEMS DESCRIPTION

A sample of flue gas is extracted by a dilution probe. The sample is diluted with dry gas and transported to the analyzers. Using this approach, the sample is on a “wet basis” since the moisture in the flue gas is not condensed in the sampling system. The flue gas flowrate is measured at virtually the same location. The reference method sampling ports where certification tests will be performed are also near the location of the probe and flow monitors.

The diluted gas sample will be transported to the analyzers through Teflon tubing. The analyzers are located in weather-proof shelters with environmental controls. The DAHS collects all data from the flow monitors and each analyzer as well as fuel data from the boilers. Reports are generated by the DAHS.

The opacity monitors are located in the stacks approximately 80 ft above grade. Although not part of the NO_x monitoring system, the DAHS also collects and reports opacity data.

Attachment 2 shows a layout of the system with the CEMS components at the ducts, the CEM shelters, the sampling ports, and the distances to upstream and downstream disturbances. Attachment 3 is a schematic data flow diagram for Boilers 1 and 2 and the equipment in CEM Shelter 1. The diagram shows the piping/tubing connections, wiring connections, and inputs to the DAHS from the boiler control rooms. The same information is shown in Attachment 4 for Boilers 3 and 4 and CEM Shelter 2.

2.1.1 CEMS Enclosures

The CEM shelters from Metal Systems are constructed of mild steel components that are individually painted with polyurethane enamel. A seamless galvanized roof prevents any potential for leaks due to corrosion or material separation. The heating, ventilation, and air-conditioning system is designed to keep the building at a constant 68°F year-round. This ensures a stable environment for the CEMS analyzers.

2.1.2 Dilution Probe

The Dilution Probe Model 797 manufactured by EPM Environmental performs several functions to prepare the stack gas sample. Clean, pressurized dilution air is blown through the sharp nozzle of the ejector pump (air driven aspirator) into a venturi. A built-in heat exchanger preheats the pressurized air to the stack temperature. The flow of pressurized air through the nozzle creates a partial vacuum within the chamber, which is also connected to the low pressure end of a critical orifice. The vacuum, in turn, extracts a constant flow of sample from the stack, through filters, to the venturi outlet, where it is diluted and mixed with the clean, pressurized air. The diluted sample is then transported at positive pressure to the analyzers via an unheated line. In order to maintain a constant flow rate through the critical orifice (and keep the orifice functioning within its critical range), the partial vacuum is kept at a pressure below 7.4 psi. The dilution probe will initially be configured to dilute flue gases 200:1.

The Model 797 Dilution Probe information is as follows:

Material	Nickel Alloy
Maximum temperature	752°F

2.1.3 Flow Control Panel

The flow control panels manufactured by URS/MS Technology, Inc., control the distribution of pressurized plant air to the Model 797 Dilution Probe. Solenoids/flow meters allow for the measurement and control of “blowback” air and calibration gas. The filtered stack gas sample is distributed by the flow control panel to both the NO_x and CO₂ analyzers. The heated filter head assembly in the probe also has connections for a calibration line and a blowback line. The flow control panel contains the sample, calibration, blowback, and exhaust manifolds. The CEMS will periodically perform an automatic blowback of the sampling system to keep particulate and debris from building up on the probe filters, in the sample line, and in the probe. Once every 24 hours, the CEMS will automatically perform an automated calibration of the NO_x and CO₂ analyzers. Ultra-high purity nitrogen serves as the zero calibration gas for both the NO_x and CO₂ analyzers. A NO_x U.S. Environmental Protection Agency (EPA) Protocol 1 calibration gas will be used to perform the span calibration on the NO_x analyzer, while a CO₂ EPA Protocol 1 calibration gas will be used to perform the span calibration on the CO₂ analyzer. The calibration line ends in the front compartment of the probe assembly. This ensures that calibration gas is supplied at the same location and under the same temperature and pressure conditions at which stack sampling takes place.

2.2 CEMS POLLUTANT ANALYZERS

2.2.1 Nitrogen Oxide

The NO_x analyzers, Model 200AH, are manufactured by Advanced Pollution Instrumentation. The Model 200AH NO_x analyzer operates on the principle of chemiluminescence detection and is referred to as an ambient level analyzer. The NO_x analyzer simultaneously determines the NO_x and nitrogen oxide (NO) concentration of the stack gas and then calculates the nitrogen dioxide (NO₂) concentration by subtraction. Model 200AH uses a combination of (1) the dual cross flow modulation type chemiluminescence principle and (2) the referencial calculation method. This gives the analyzer the flexibility of use in single-detector mode or to perform continuous measurements for NO_x, NO₂, and NO. This design also provides stability and sensitivity. The effective range of measurement for NO_x is from 0.1 to 5000 parts per million (ppm).

The Model 200AH specifications are as follows:

Full-scale range (initial configuration)	1000 ppm
Minimum detection level (initial configuration)	8 ppm
Noise level	<0.2% of full-scale
Zero drift (24 hours)	<20 ppb
Span drift (24 hours)	<1.0% of full-scale
Linearity	1.0% of full-scale
Precision	0.5% of full-scale

2.2.2 Carbon Dioxide

The CO₂ analyzers, Model 360, are also manufactured by Advanced Pollution Instrumentation. The CO₂ analyzer operates on the principle of gas filter correlation. The effective range of detection for CO₂ is from 0.2 to 1000 ppm. The Model 360 measures CO₂ by comparing infrared energy absorbed by a sample to that absorbed by a reference according to the Beer-Lambert law. This is accomplished by using a gas filter wheel that alternately allows a high-energy infrared light source to pass through a CO₂-filled chamber and a chamber with no CO₂ present. The light then travels through the sample cell, which has a folded path. The energy loss through the sample cell is compared with the zero references signal provided by the gas filter to produce an output proportional to concentration, with little effect from interfering gases within the sample.

The Model 360 specifications are as follows:

Full-scale range (initial configuration)	20%
Minimum detection level (initial configuration)	0.01%
Noise level	<1% of full-scale
Zero drift (24 hours)	<0.25 ppm
Span drift (24 hours)	<0.5% of full-scale
Linearity	1.0% of full-scale
Precision	1.0% of full-scale

2.2.3 Flue Gas Flowmeter

The ultrasonic flow monitors, Ultraflow 150, are manufactured by Monitor Labs and will be used to determine the volumetric flow rate of each duct leading from the reverse air baghouses. Ultrasonic flow devices measure the tone bursts (signals) between pairs of sensors. The Ultraflow 150 does not protrude into a stack and is a non-intrusive means of measuring gas flow. With this configuration, the unit is protected from erosion, corrosion, and agglomeration of material on the transducers. The flowmeter integrates velocity vectors along the transducer path to calculate velocity. A dual set of transducers (four total) will be installed on opposite sides of the ductwork in an “X” pattern. This will eliminate any adverse effects due to pitch flow. Calibration checks will be automatically conducted each day (or on demand) to fully test the signal transmission, reception, and processing. The flowmeter will be configured with temperature and pressure measuring instrumentation to convert the output to standard conditions (68°F, 29.92 in. Hg.).

The Ultraflow 150 specifications are as follows:

Full-scale range (initial configuration)	3700 std ft/min
Accuracy	+/- 18 ft/min
Drift (24 hours)	+/- 1% full-scale
Maximum temperature	650°F

2.2.4 Opacity

The opacity monitors, Model LH-560, are manufactured by Monitor Labs and will be mounted in each stack. The light source is an electronically modulated, intensity controlled light emitting diode (LED) located in the optical head assembly. Light from the LED is projected from the optical head across the stack to a retroreflector on the opposite side. The reflected light re-enters the optical head, where it is

evaluated by a signal detector. If the stack is clear, the light transmission is 100% and the opacity is 0%. When the stack gasses absorb all the light and none is reflected back, the transmission is zero or 100% opacity. Purge air continuously purges both units to protect them from particulate material and stack gases. The optical head and retroreflector are constructed of heavy gage aluminum and finished with acid-resistant enamel paint. Exposed hardware is stainless steel.

The Model LH-560 specifications are as follows:

Optical measurement technique	Double Pass Extinction
Angle of view	<4°
Angle of projection	<4°
Spectral response	Peak 500–600 nm
	Mean 500–600 nm
Calibration error	<2%
Zero drift (24 hours)	<0.4%
Span drift (24 hours)	<0.4%
Maximum temperature	500°F

2.3 FUEL MONITORING

2.3.1 Coal Feed and Heat Content

Coal is supplied to each boiler from coal bunkers. Coal is fed to each boiler by two belt-type coal feeders (refer to Attachment 1) that are associated with the individual boilers. There are eight coal feeders for the four boilers. Varying the speed of the belt feeders controls the coal feed rate. The coal rate for each feeder is monitored separately and supplied as an input to the DAHS.

The source of coal is the same for all the boilers. A coal sample is obtained daily from the coal feeders. Gross calorific value (GCV) is determined by analyzing a weekly composite. The weekly GCV value will be input into the DAHS for the heat input calculations described in Section 3. Vendor information is included in Attachment 5.

Identification information for the coal feeders are as follows:

Manufacturer:	Merrick
Model:	Coalometer 480
Belt width:	38 in.
Full-scale range	15,000 lb/hour/feeder (30,000 lb/hour/boiler)

2.3.2 Natural Gas Flow and Heat Content

Natural gas is supplied to each boiler from a pipeline (currently Duke Energy Gas Transmission Co.). When burning coal, natural gas may be burned simultaneously in igniters (refer to Attachment 1) for flame stability. An orifice meter monitors the natural gas flow to the igniters. The boilers may also be fired on natural gas only. Separate orifice meters measure the natural gas flow to the burners. An orifice meter that monitors natural gas flow to the igniters and an orifice meter that measures natural gas flow to

the main burners are associated with each boiler. The total natural gas flow to each boiler is summed and supplied as an input to the DAHS.

The source of natural gas is the same for all the boilers. The GCV is available from the supplier via a weblink. The weekly GCV value from the weblink will be input into the DAHS for the heat input calculations described in Section 3. Vendor information is included in Attachment 5.

Identification information for the orifice meters are as follows:

Transducer manufacturer	Bailey-Fischer & Porter
Model	BC24215140

Igniter full-scale range	30,000 scfh
Igniter orifice plate:	
Material	stainless steel
Thickness	0.125 in.
Pipe size	3 in. diameter
Orifice size	1.689 in. diameter

Main burner full-scale range	450,000 scfh
Main burner orifice plate:	
Material	stainless steel
Thickness	0.125 in.
Pipe size	8 in. diameter
Orifice size	4.787 in. diameter

2.4 DAHS DESCRIPTION

Raw data from the CEMS and fuel flow monitoring systems and plant signals will enter the DAHS Model 8832. The DAHS computer will generate final averages, perform emission rate calculations, and generate the quarterly electronic data reports (EDRs) as well as hard copy reports. The initial EDR printouts are enclosed as Attachment 6.

The DAHS Model 8832 manufactured by ESC continuously records and stores emissions data and also controls automatic system features such as calibrations. The DAHS records and stores the emission parameters for NO_x, CO₂, volumetric flow, and opacity. When not being used for other purposes, the DAHS will typically display real-time emissions data for NO_x and opacity on the computer screen. The DAHS uses NO_x and CO₂ 1-minute averages to calculate the NO_x mass emission rate (MER) (lb/MMBtu). The CEMS allows calibrations and other system features to be performed manually or automatically. The DAHS is pre-configured to perform an automated calibration every 24 hours. The DAHS continuously transfers data to the computer hard drive, where the user can retrieve and print historical calibration and emissions data for any time period desired using the DAHS software.

The DAHS will be configured to capture and log system events, such as maintenance, manual and automated calibrations, alarms, and excessive calibration drift. The DAHS can also be configured such that an acknowledgement and/or explanation is required to be entered by the system operator for certain events. The event log can be used to satisfy 40 CFR 75, Appendix H maintenance and alarm

recordkeeping requirements. An uninterrupted power supply/power conditioner will be provided for the DAHS and the associated computers and monitors.

The Model 8832 specifications are as follows:

Resolution	14-bit
Front-to-back accuracy	+/- 0.1%
Scan Rate:	32 channels per second
CPU	80C188EB, 16 MHz
Battery backup	30 days minimum (50 mA-hour rechargeable)

3. NO_x EMISSIONS

The variables to be monitored by the NO_x budget CEMS and plant instrumentation subject to the provisions of Part 75 are as follows:

- NO_x concentration, ppmv (wet basis)
- CO₂ concentration, ppmv (wet basis)
- Volumetric flowrate, scfm (wet basis)
- Coal feed rate, lb/hour
- Natural gas flowrate, scfh/hour

Based on the measured variables, the NO_x Budget CEMS calculates real-time data for:

- F-Factor, scf of CO₂/MMBtu (combined based on heat inputs of coal and natural gas)
- Hourly heat input, MMBtu/hour
- Hourly NO_x mass emissions, lb/MMBtu and lb/hour

3.1 EQUATIONS

The specific equations used to calculate each monitored parameter are detailed as follows:

Hourly Heat Input of Natural Gas

Heat input rate, $HI_{gas} = (Q_{gas} \times GCV_{gas})/1,000,000$

where:

HI_{gas} = Hourly natural gas heat input rate, MMBtu/hour,

Q_{gas} = Hourly volumetric flow rate of natural gas, scfh,

GCV_{gas} = Gross calorific value of natural gas, Btu/scf.

Hourly Heat Input of Coal

Heat input rate, $HI_{coal} = (Q_{coal} \times GCV_{coal})/1,000,000$

where:

HI_{coal} = Hourly coal heat input rate, MMBtu/hour,

Q_{coal} = Hourly mass rate of coal from both coal feeders ($Coal_1 + Coal_2$), lb/hour,

GCV_{coal} = Gross calorific value of coal, Btu/lb.

Total Heat Input

Heat input rate, $HI_{total} = HI_{coal} + HI_{gas}$

Combined Carbon Based F-factor

$F_c = (1800 \times HI_{coal}/HI_{total}) + (1040 \times HI_{gas}/HI_{total})$

where:

F_c = Combined carbon-based F-factor for coal and gas, scf CO₂/MMBtu,

1800 = F_c for coal, scf CO₂/MMBtu,

1040 = F_c for natural gas, scf CO₂/MMBtu.

NO_x Emission Rate

$$E = K \times C_w \times F_c \times 100/\%CO_{2w}$$

where:

E = NO_x MER, lb/MMBtu,

K = 1.194×10^{-7} , lb/scf/ppm,

C_w = NO_x concentration, ppm (wet),

F_c = Combined carbon-based F-factor, scf CO₂/MMBtu,

$\%CO_{2w}$ = CO₂ diluent concentration, % (wet).

NO_x Mass Emission Rate

$$NOXM = K \times C_w \times Q_h$$

where:

NOXM = Hourly NO_x emissions, lb/hour,

$K = 1.194 \times 10^{-7}$, lb/scf/ppm,

C_w = Hourly average NO_x concentration, ppm (wet),

Q_h = Hourly average volumetric flow rate, scfh (wet).

3.2 MAXIMUM POTENTIAL CONCENTRATIONS, SPANS, AND DAILY CALIBRATIONS

The maximum potential concentration (MPC) of NO_x for the initial period will be 800 ppm. This is the default value listed in Option 1 for coal-fired units in 40 CFR 75, Appendix A, 2.1.2.1. Likewise, the MPC of CO₂ for the initial period will be 14.0%, the default value listed 40 CFR 75, Appendix A, 2.1.3.1.

The boilers may also operate on natural gas alone. The default NO_x MPC for natural gas combustion is 400 ppm (40 CFR 75 Appendix A, 2.1.3.1), which is within the 20–80% range of the analyzer. Consequently, it is not anticipated that a dual-range monitoring mode will be required. After evaluating the operation data, if a majority of readings during typical operation fall outside the initial range, one of two options will be implemented.

1. Adjust span and range. This may be accomplished either by rescaling the NO_x analyzer or changing the dilution ratio of the dilution probe. If this change requires changing the daily upscale calibration gas, a linearity check using appropriate gases will be performed for the new range.
2. Operate with dual ranges. This may be accomplished by establishing high and low operating ranges. With this option, daily calibrations will be performed with upscale gases for both the high and low ranges. A linearity check using appropriate gases will be performed on the new range.

The maximum potential flowrate, based on test data at near maximum steam production, was approximately 80,000 wscfm or 4,800,000 wscfh. The cross-sectional area in all the boiler ducts where

the flowmeters will be installed is 27 ft². Consequently, the maximum potential velocity is approximately 3000 ft/min (wet, standard).

Based on these values, the following table lists the MPCs, MPV, MPF, spans, ranges, and daily calibrations.

Parameter	MPC/MPF/MPV	Span	Full-scale	Daily calibration
NO _x	800 ppm	800 ppm	1000 ppm	800 ppm
CO ₂	14 %	16 %	20%	16%
Fluegas flowrate	4,800,000 wscfh	6,000,000 wscfh	6,000,000 wscfh	100% ^a
Fluegas velocity	3,000 wsft/min	3700 wsft/min	3700 wsft/min	100% ^a

^aEquipment to 3,700 wsft/min and 6,000,000 scfh.

These values will be re-evaluated using collected data as called for by 40 CFR 75, Appendix A.

3.3 NO_x MAXIMUM EMISSION RATE

For data substitution purposes during the initial period, the maximum potential NO_x MER will be determined as required by 40 CFR 75, Appendix A, Subsection 2.1.2.1(b). The MER will be calculated based on Equation F-6 in Section 3.3 of 40 CFR 75, Appendix F, which for this application takes the form:

$$E_{\max} = K \times C \times F_c \times 100/\%CO_2$$

where:

E_{\max} = Maximum potential NO_x MER, lb/MMBtu,

$K = 1.194 \times 10^{-7}$, lb/scf/ppm,

$C = 800$ ppm - NO_x MPC,

$F_c = 1800$ scf CO₂/MMBtu - Carbon-based F-factor for coal,

%CO₂ = 5% - Minimum CO₂ cap concentration (diluent cap).

$$E_{\max} = 3.4 \text{ lb NO}_x/\text{MMBtu}$$

Statistical values will be used for the NO_x emission rate for data substitution once adequate quality assured monitoring data are available.

4. QUALITY ASSURANCE/QUALITY CONTROL ACTIVITIES

This section summarizes the overall approach to QA and QC that will be implemented during operation of the continuous emissions monitoring program for the Y-12 Steam Plant. Sections 4.2 through 4.5 identify the QA/QC checks and tests that are required to be performed on a routine and periodic basis, along with the corresponding acceptance criteria, in order to demonstrate that the CEMS are producing valid measurement data. Section 4.6 describes the identification and handling of periods of missing data. Section 4.7 summarizes the various notifications and submittals prior to and during operation of the plant.

4.1 ORGANIZATION AND RESPONSIBILITIES

This section summarizes the key responsibilities for implementing the continuous emissions monitoring program for the Y-12 Steam Plant in accordance with 40 CFR 75, Appendix B, and 40 CFR 60 Appendix B.

Table 4.1. Key responsibilities

Title	Responsibilities
Operations Manager	<ul style="list-style-type: none">• Boiler operations
Operations Manager Designee	<ul style="list-style-type: none">• Data validation• QA/QC documentation and supervision• Report generation
	<ul style="list-style-type: none">• Daily data review• Daily CEMS inspection
	<ul style="list-style-type: none">• CEMS operation and maintenance• Procure related CEMS equipment/materials
Authorized Account Representative (AAR) Alternate AAR	<ul style="list-style-type: none">• Submittal of notifications, Monitoring Plan and updates, Initial Certification Test Protocol, hard copy and electronic Initial Certification Test Reports, periodic Relative Accuracy Test Audit (RATA) Testing Notifications, Quarterly Monitoring Data Reports, Compliance Certification Statements

4.1.1 Emissions Data Review and Emission Report Generation

All related measurement data will be recorded, reduced and validated properly (including pollutant concentrations, fuel flow measurements, and periodic testing of fuel characteristics). Data review will include comparisons with QA/QC acceptance criteria and permit limits, evaluations for trends in general and in relation to plant operating conditions. Hard copy and electronic quarterly monitoring data reports will be produced for AAR or alternate AAR review and certification prior to submittal in accordance with regulatory submittal requirements.

4.1.2 Training

Staff responsible for operating and maintaining the CEMS and for interpreting CEMS output by the DAHS will be trained by the CEM manufacturer. Ongoing training will be conducted on an as-needed basis by BWXT.

4.1.3 Review of Data, Other Operating Information, and QA/QC Check Results

Hard copy or electronic CEMS data reports generated on a daily basis by the DAHS include calibration error reports and data summary reports. These will be reviewed. Other DAHS output that will be inspected regularly include flue gas flowrate reports, excess emissions reports, monitor downtime reports, unit downtime reports, and linearity check reports.

4.1.4 Daily CEMS Equipment Inspections and Documentation

Personnel will inspect the CEMS equipment and shelters on a daily basis (e.g., analyzer and equipment settings and readouts, alarms appearing on instrumentation or generated by the DAHS, calibration gas bottle pressures and inventory, shelter heating and air conditioning controls, and housekeeping).

Inspection records will be retained electronically or in hardcopy. Shelter visits will also be documented in a hardcopy logbook maintained in each shelter. Entries will be made when any adjustments or other changes to an instrument or related equipment occur and will identify the date, time, person making the visit, its purpose, and a summary of any relevant observations, readouts, results, or changes made.

4.1.5 Maintenance Documentation

Personnel will document when maintenance is performed and describe the problem and any corrective actions taken. For problems not able to be resolved the same day, an assessment as to the affect on data validity will be made along with an estimate of the length of time required to resolve the issue. In the case of an instrument being or having to be taken out of service, appropriate personnel will be notified to evaluate the potential effects on data recovery, data substitution, monitor uptime/downtime statistics, and whether it is necessary to request and mobilize backup measurement equipment in accordance with the applicable regulations.

Maintenance documentation will be maintained electronically or in hardcopy. This documentation will be available to responsible personnel. Any hardcopy documentation generated will be retained in the plant central file.

4.2 PERIODIC QA/QC REQUIREMENTS

Under the NO_x Budget Program, acceptable operation of CEMS is first established through initial certification of the CEMS pursuant to 40 CFR 75.20(c) and the procedures in Appendix A to Part 75. Initial CEMS certification comprises a series of tests, including a 7-day zero- and high-level calibration error test, a linearity test, and a cycle (or response) time test, followed by a RATA and bias test. For the Y-12 Steam Plant, these requirements apply to the continuous measurement of NO_x and CO₂ emissions and the flue gas flowrate monitors.

Acceptable operation of the opacity monitors is initially established through demonstration that the monitors meet Performance Specification 1 (PS 1) in 40 CFR 60, Appendix B. These tests include calibration error tests, response time tests, and calibration drift tests.

Following successful completion of these tests, routine operation and maintenance of the CEMS are governed by the QA/QC requirements of 40 CFR 75, Appendix B and 40 CFR 60, Appendix B. The matrix in the table below identifies the various QA/QC checks to be performed based on these regulations. More detailed information regarding initial certification is presented in the Initial CEMS Certification Test Protocol in Attachment 7.

Table 4.2. Required QA tests

Parameter	Daily calibration	Quarterly linearity/check	Quarterly flow-to-load	RATA^a	Bias test^b	Biennial
NO _x	CE	T		T	T	
CO ₂	CE	T		T		
Fluegas Flow	IC		T	T	T	
Opacity	CD					CE

CE = Calibration Error

CD = Calibration Drift

IC = Interference Check

^aFrequency depends on accuracy of previous RATA.

^bBias Test and Adjustment Factor, 40 CFR 75, Appendix A, Section 3.4, 6.5, and 7.6 requirements.

Sections 4.3 through 4.5 provide additional details regarding these various QA/QC checks.

4.3 CALIBRATION ERROR/CALIBRATION DRIFT CHECKS/INTERFERENCE CHECKS

This section identifies the acceptance criteria for calibration error (NO_x and CO₂ concentration monitors) applicable to initial certification or performance evaluations of CEMS under 40 CFR 75 and on a daily basis during routine operation. For gaseous pollutant analyzers, calibration error and calibration drift are synonymous terms.

For initial certification of NO_x and CO₂ CEMS, calibration error checks are governed by 40 CFR 75, Appendix A, Section 6.3. For these tests, the calibration error is considered to be acceptable if both the zero and high-level calibration responses, on each of seven consecutive unit operating days, differ from the reference gas concentration by:

- $\leq 2.5\%$ of instrument span for NO_x and CO₂,
or $< 0.5\%$ CO₂ difference for CO₂
- $\leq 3.0\%$ span for flow monitor

During routine CEMS operation, calibration error, calibration drift, and interference checks are used to evaluate the stability of analyzer response on a day-to-day basis and to determine whether the instrument is producing valid, quality-assured data or is out of control. For the NO_x and CO₂ analyzers, the requirement for daily calibration error checks is established at 40 CFR 75, Appendix B, Sect. 2. 1. For the opacity analyzer, the requirement for daily calibration drift checks is established at 40 CFR 60, Appendix B, PS 1.

Zero and high-level calibration error and drift response are considered to be acceptable on a daily basis, and the measurement data are considered to be valid, if the specifications given above for initial

certification and performance evaluations are met. Measurements are still considered to be valid if the calibration error and drift responses are less than or equal to twice these specifications (i.e., $\leq 5.0\%$ of instrument span for NO_x and $\leq 1.0\%$ CO_2 difference for CO_2). However, when an analyzer has a zero or high-level response between the respective performance specification and twice that value, the monitor must be inspected and re-calibrated.

When a zero or high-level calibration response exceeds twice the corresponding performance specification for a NO_x or CO_2 analyzer, the instrument is considered to be out of control, corrective action must be taken, and the measurement data are considered to be invalid until the successful completion of another calibration error test.

4.4 RELATIVE ACCURACY TEST AUDITS

RATAs are used to establish the ability of a CEMS to accurately measure and report a given pollutant concentration or emissions rate from an affected source and to determine any bias in those measurements. The RATA is required for initial CEMS certification and, depending on those results, must be performed periodically thereafter during routine operation of the source. These relative accuracy and bias tests will be carried out in accordance with the procedures in 40 CFR 75, Appendix A, Sect. 6.5.

For Part 75 purposes, the RATA test and bias determination will be conducted on the NO_x analyzer, diluent (CO_2) analyzer, and flue gas flowrate monitor. The gas concentration RATA will be performed while the unit is operating at normal (high steam rate) conditions by comparing the results from the CEMS to concurrent measurements from Reference Method analyzers over a prescribed series of test runs. Flow RATA tests will be performed at low, mid, and normal (high) steam rates. Additional information is presented in the Certification Test Protocol (Attachment 7).

As indicated in 40 CFR 75, Appendix A, Sect. 3.3, relative accuracy test results are considered to be acceptable for the NO_x and CO_2 concentration monitors and flowrate monitor if the relative accuracy is determined to be $\leq 10\%$. The regulations also provide alternative acceptance criteria as follows:

- CO_2 . The relative accuracy is also acceptable if the difference between the mean values of the CEMS measurements and the Reference Method does not exceed $\pm 1.0\% \text{ CO}_2$.
- Flue gas Flowrate. The relative accuracy is also acceptable if the velocity is $<10 \text{ ft/sec}$ and the difference is $<2 \text{ ft/sec}$.

On a routine operating basis, an analyzer is considered to be out of control if these limits are exceeded.

For Part 75 purposes, NO_x -diluent CEMS and flue gas flowrate monitors analyzers that meet the limits specified above are required to perform relative accuracy and bias (NO_x only) testing on a semiannual basis in accordance with 40 CFR 75, Appendix B, Sect. 2.3.1.1. However, since this system will only be used during the ozone season, an annual RATA will suffice. EPA has instituted an "Accuracy Test Frequency Incentive System" where future RATAs may be performed less frequently. This is available to systems that perform better than required and carry out all daily calibrations. This option will be used if applicable for scheduling future RATAs.

4.5 LINEARITY CHECKS

Linearity checks are used for the periodic evaluation of data validity (i.e., at least once each QA operating quarter) by confirming the linearity of instrument response in accordance with 40 CFR 75, Appendix B, Sect. 2.2.1. They are also required for initial CEMS certification. These checks will be carried out in accordance with the procedures in 40 CFR 75, Appendix A, Sect. 6.2.

These checks will be conducted on the NO_x and CO₂ (diluent) CEMS. The linearity checks will be conducted while the unit is combusting fuel at typical duct temperatures and pressure.

Instrument response is checked at three concentration levels (low, mid, and high) using EPA Protocol 1-Certified test gases as required by 40 CFR 75, Sect. 5.2. These levels are defined as follows:

Analyzer	Daily span	Concentrations for linearity check		
		Low	Mid	High
NO _x	800 ppm	160–240 ppm	400–480 ppm	640–800 ppm
CO ₂	16%	3–5%	8–10%	13–16%

As indicated in 40 CFR 75, Appendix A, Sect. 3.2, linearity test results are considered to be acceptable for the NO_x and CO₂ concentration monitors if the difference between the known check gas concentration and the analyzer response is $\leq 5\%$ of the reference concentration at each reference level. The regulations provide alternative acceptance criteria as follows:

- NO_x. If the absolute value of the difference between the average of the monitor response values at a given level and the reference value is ≤ 5 ppm.
- CO₂. If the absolute value of the difference between the average of the monitor response values at a given level and the reference value is $\leq 0.5\%$ CO₂, whichever is less restrictive.

On a routine operating basis, the analyzer is considered to be out of control if these limits are exceeded.

The calibration error test for the opacity monitor involves inserting three certified calibration attenuators (low, mid, and high range) in the transmissometer path at or as near the midpoint of the path as feasible. Five nonconsecutive readings are recorded for each attenuator. The arithmetic difference between the observed readings and the certified attenuator actual values is calculated for each of the 15 readings. The arithmetic difference of the 15 readings is then used to calculate the arithmetic mean, confidence coefficient, and calibration error value for each range. The system calibration error for each range must be less than or equal to 3% opacity in order to pass this part of the performance specification.

4.6 FLOW-TO-LOAD RATIO

The flow-to-load ratio will be examined quarterly. The flow-to-load ratio is the ratio of flue gas flow rate (scfh) to boiler load (1000 lb steam/hour). Hourly data where the boiler load was within 10% of the load during the most recent RATA will be compared to the reference flow-to-load obtained during the RATA.

4.7 MISSING DATA SUBSTITUTION PROCEDURES

This section summarizes the missing data substitution procedures to be followed for missing flowrate, NO_x concentration, and the NO_x-diluent (CO₂) CEMS measurements.

When either the NO_x analyzer, CO₂ monitor, flowrate monitors or combination are out-of-control and not producing quality assured data for a given hour, the DAHS will utilize the procedures delineated in 40 CFR 75.31 through 75.33 and Appendix C to fill in the missing data. The DAHS will store data (in scfh, ppm, and MMBtu/hour) in the DAHS database.

The initial missing data procedures of 40 CFR 75.31(c) apply to these measurements during the first 2160 quality assured monitor operating hours. Quality assured monitor operating hours and monitor data availability procedures after the initial 2160 hours are accumulated will be determined in accordance with 40 CFR 75.32. For any missing data hour(s) where data are either not provided or are considered invalid as described previously, substitute data will be inserted based on the procedures described in 40 CFR 75.33(c). Table 4.3 shows how the substitute data will be calculated based on CEMS availability.

Table 4.3. Missing data procedure

Trigger conditions		Calculation routines		
Monitor data availability (percent)	Duration of (N) of CEMS outage (hours)	Method	Look back	Ranges
95 or more	N#24 N>24	Average The greater of: Average 90th percentile	2160 hours ^a HB/HA 2160 hours ^a	Yes No Yes
90 or more, but below 95	N#8 N>8	Average The greater of: Average 95th Percentile	2160 hours ^a HB/HA 2160 hours ^a	Yes No Yes
80 or more, but below 90	N>0	Maximum value	2160 hours ^a	Yes
Below 80	N>0	Maximum potential flowrate, potential NO _x concentration, or potential NO _x emission rate	None	No

HB/HA = hour before and hour after the CEMS outage

^aQuality assured, monitor operating hours, using data at the corresponding range ("bin") for each hour of the missing data period.

Flue gas flowrate (scfh), NO_x emission rate (lb/MMBtu), and NO_x concentration (ppm) data will be saved for use as substitute data. Data will be collected in the following 10 operating ranges. For this system, equivalent steam load may be determined from heat input.

Load Range	Steam load (1,000 lb/hour) ^a
1	0–20
2	>20–40
3	>40–60
4	>60–80
5	>80–100
6	>100–120
7	>120–140
8	>140–160

Load Range	Steam load (1,000 lb/hour) ^a
9	>160–180
10	>180–200

^a or equivalent, steam load determined from heat input.

4.8 NOTIFICATIONS AND SUBMITTALS

4.8.1 Monitoring Plan

An electronic Monitoring Plan file has been prepared in accordance with EPA's EDR Instructions (Version 2.2) and will be submitted to EPA's Clean Air Markets Division (EPA-CAMD) no later than 21 days prior to the start of initial certification testing pursuant to 40 CFR 75.62(a)(1). In the future, an up-to-date version of this file will also be submitted at the time of each certification or re-certification application and in each electronic quarterly report.

An evaluation of this electronic file has been performed using EPA's Monitor Data Checking (MDC) software (Version 4.1 Beta). The results for this initial submittal are presented in Attachment 6. Subsequent transmittals will also be evaluated using the current version of the MDC software.

Hardcopy information required under 40 CFR 75.53(e) and (f) or any other related guidance (e.g., EDR Instructions, Policy Manual) will be submitted to TDEC and EPA Region IV at least 21 days prior to the start of initial certification testing. Thereafter, changes to the hardcopy version of the document will be submitted only as part of a re-certification application (if a particular portion of the Monitoring Plan is revised as a result of the re-certification event) or within 30 days of any other event requiring a change to the hardcopy Monitoring Plan.

Electronic submittal of all Monitoring Plan information, including the hardcopy portions, is permissible provided that a paper copy of the hardcopy version can be provided to the requesting agency upon request.

4.8.2 Initial CEMS Certification and Recertification

Notice of testing for initial certification, for full re-certification tests, and for revised test dates is required pursuant to 40 CFR 75.61(a). In compliance with these regulations, initial certification test notifications will be submitted to EPA-CAMD, EPA Region IV, and TDEC no later than 21 days prior to the first scheduled day of testing. If rescheduling becomes necessary, notice of the new date will be provided either in writing, by telephone, or by other acceptable means at least 7 days prior to the originally scheduled test date or the revised test date (whichever is earlier).

In accordance with 40 CFR 75.61(a)(1), notification for re-testing following the loss of certification under 40 CFR 75.20(a)(5) or for re-certification under 40 CFR 75.20(b) will be provided by acceptable means at least 7 days prior to the first scheduled day of testing. In emergency situations, when testing is required following an uncontrollable failure of equipment that results in lost data, notice will be provided within two business days following the date when testing is scheduled. If re-scheduling becomes necessary, notice of the new date will be provided by acceptable means at least 2 days prior to the original or the revised test date (whichever is earlier).

As allowed under 40 CFR 75.61(a)(1)(iii), a certification test may be repeated immediately, without advance notification, when it has been determined during the scheduled or re-scheduled certification

testing that a test was failed or that a second test is necessary in order to attain a reduced testing frequency.

Pursuant to 40 CFR 75.63, an electronic version of the Monitoring Plan with the certification test results and hardcopy documentation of certification test results will be provided to EPA-CAMD within 45 days of test completion. Copies of the hardcopy documentation will be provided to EPA Region IV and TDEC within this same period. A certification or recertification application form will also accompany each of these submittals.

4.8.3 Periodic RATAs

As indicated in Sect. 4.2, periodic relative accuracy testing is required to be performed pursuant to 40 CFR 75, Appendix B, Sect. 2.3.1. Written notice of the planned date for such testing will be provided to EPA-CAMD, EPA Region IV, and TDEC no later than 21 days prior to the first scheduled day of testing in accordance with 40 CFR 75.61(a)(5).

If re-scheduling becomes necessary, notice of the new date will be provided by acceptable means (e.g., in writing, by telephone, electronic mail, or facsimile) as soon as practicable after the new test date is known, but no later than 24 hours in advance of the new date. Periodic relative accuracy testing may be repeated immediately, without additional notification, if it has been determined that a test has failed or that a second test is necessary in order to attain a reduced testing frequency.

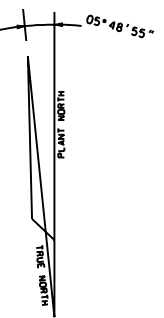
Waivers from the notification requirements applicable to periodic relative accuracy testing may also be sought under 40 CFR 75.61(a)(5)(iii).

4.8.4 Quarterly Reports

Electronic reports of monitoring data and related operating information (including electronic Monitoring Plan records) will be submitted to EPA-CAMD within 30 days of the end of each calendar quarter, pursuant to 40 CFR 75.64. The initial quarterly report will contain data beginning with the day and hour of provisional certification. These reports will be prepared in accordance with the file record structures detailed in EPA's EDR Instructions (currently at Version 2.2). These reports will be submitted quarterly to the TDEC Office in Nashville and to the Air Enforcement Branch of EPA Region IV.

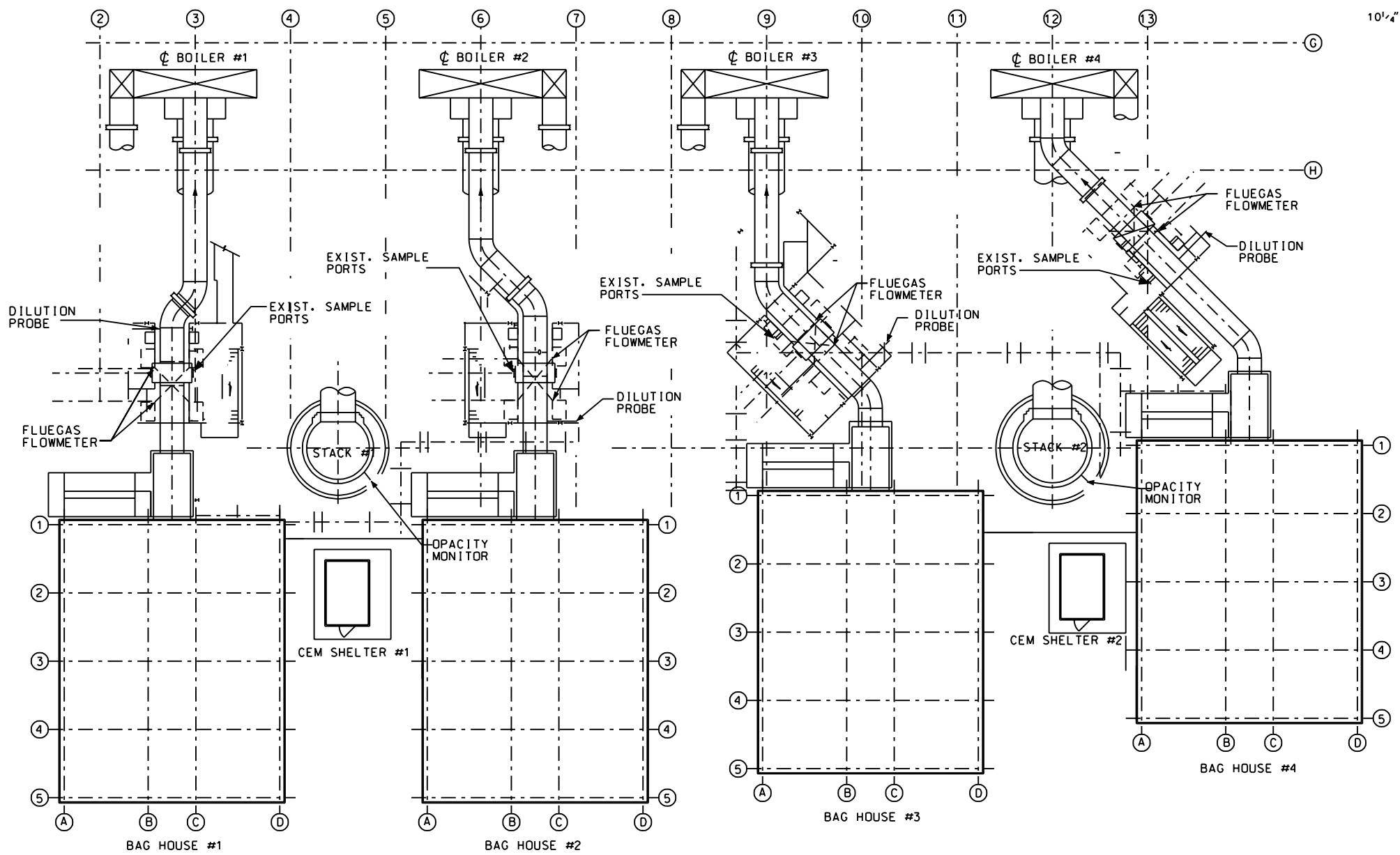
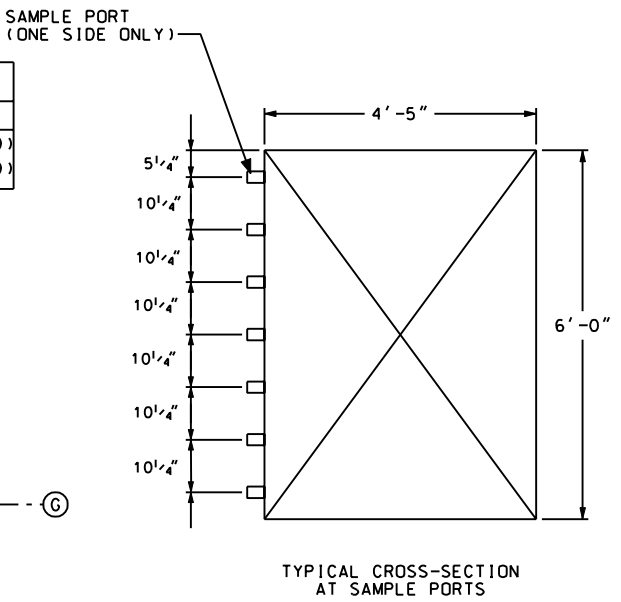
Attachment 1
Boiler Fuel and Fluegas Schematic

Attachment 2
System Layout



	Boiler 1		Boiler 2		Boiler 3		Boiler 4	
	Upstream	Downstream	Upstream	Downstream	Upstream	Downstream	Upstream	Downstream
Flue Gas Flowmeter	21' 9" (4.2 D)	7' 5" (1.4 D)	22' 2" (4.3 D)	7' 9" (1.5 D)	10' 1" (2.0 D)	7' 6" (1.5 D)	24' 0" (4.7 D)	16' 1" (3.1 D)
Sample Ports	31' 3" (6.1 D)	4' 3" (0.8 D)	32' 0" (6.2 D)	5' 8" (1.1 D)	18' 0" (3.5 D)	4' 11" (1.0 D)	19' 4" (3.8 D)	28' 0" (5.4 D)

Boiler 1		Boiler 2	
Upstream	Downstream	Upstream	Downstream
60' 0" (4.8 D)	113' 0" (9.0 D)	60' 0" (4.0 D)	113' 0" (7.5 D)



ORIS
880055

URS

PROJECT NAME: CEM SYSTEM Y-12 STEAM PLANT									
CEM SYSTEM LAYOUT									
3	48	58	58	58	58	58	58	58	58
1	2	3	4	5	6	7	8	9	10
1	2	3	4	5	6	7	8	9	10
1	2	3	4	5	6	7	8	9	10
1	2	3	4	5	6	7	8	9	10
1	2	3	4	5	6	7	8	9	10
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1	2	3	4	5	6	7	8	9	10

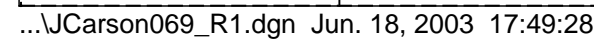
NO REPRESENTATION OR WARRANTY, EXPRESSED OR IMPLIED, IS MADE AS TO THE ACCURACY, COMPLETENESS OR USEFULNESS OF THE INFORMATION OR STATEMENTS CONTAINED IN THESE DRAWINGS, OR THAT THE USE OR DISCLOSURE OF ANY INFORMATION, APPARATUS, METHOD, OR PROCESS DISCLOSED IN THESE DRAWINGS MAY NOT IMPROVE PRIVATE RIGHTS OF OTHERS. NO LIABILITY IS ASSUMED WITH RESPECT TO THE USE OF, OR FOR DAMAGES RESULTING FROM THE USE OF ANY INFORMATION, APPARATUS, METHOD, OR PROCESS DISCLOSED IN THESE DRAWINGS. DRAWINGS MADE AVAILABLE FOR INFORMATION TO BIDDERS ARE NOT TO BE USED FOR OTHER PURPOSES AND ARE TO BE RETURNED UPON REQUEST OF THE FORWARDING CONTRACTOR.

SECTION AND DETAIL KEY

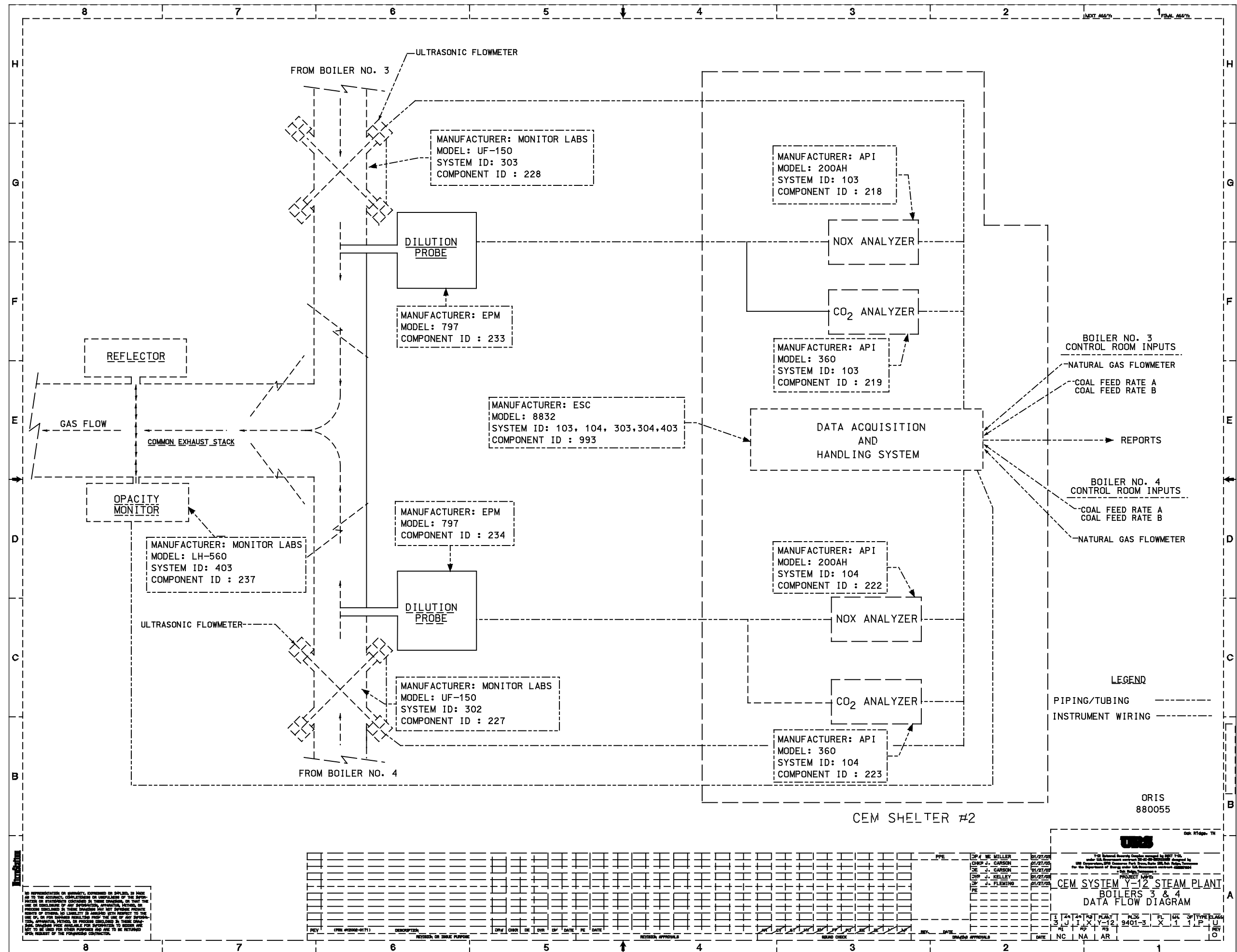
DRAWING ON WHICH SECTION OR DETAIL IS SHOWN

NUMBER OF SECTION OR DETAIL

Attachment 3
Boilers 1 and 2 Data Flow Diagram



Attachment 4
Boilers 3 and 4 Data Flow Diagram



Attachment 5

Vendor Information for Coal Feeders and Natural Gas Orifice Meters

DATA SHEET		DATA SHEET NO.	REV.	ISSUE DATE
MARTIN MARIETTA ENERGY SYSTEMS, INC. OAK RIDGE, TN		DS-YIE-785-23	A	2/25/87
PROJECT TITLE		PAGE	OF	REQUISITION NO.
STEAM PLANT GAS IGNITION		1	2	
JOB TITLE		PROCURED BY	INSTALLED BY	
IGNITION GAS FLOW		MM-ES	MM-ES	
EQUIPMENT		PROJECT NO.	E.S.O. OR W.O.	
FLOW ORIFICE AND FLANGES, FE-1026 & FE-2026		BUILDING	PLANT	
		9401-3	Y-12	

The following defines the technical requirements for an orifice plate and standard raised-face, metering flanges.

1. General Requirements

Flow Rate: 0-30, 000 scfh.
 Process Fluid: Natural Gas
 Process Temp.: 70°F
 Process Pressure: 34.6 psia
 Tagging: Metal tags to be attached to respective orifice plates.
 Process pipe: 3"

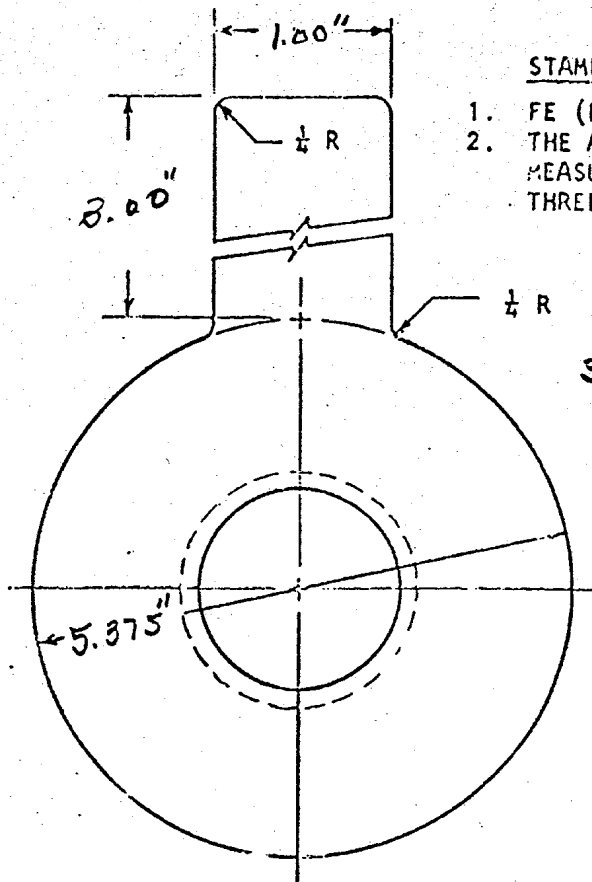
2. Orifice Plate (See sht. 2 this ds)

Material: 316 stainless steel
 Plate Thickness: 0.125"
 Class: ANSI: 300#
 Bore Size: 1.6895"
 Type: Paddle
 Orifice bore/line size (d/D): 0.5507
 Tag: FE-1026, FE-2026

3. Standard Flanges

Type: Raised face, welded neck with studs, and jackscrews
 Material: 316 stainless steel
 Line size: 3"
 Class: ANSI: 150#
 Raised Face: 1/16"
 Gaskets: 1/16", neoprene, 2 each.
 Taps: Flange

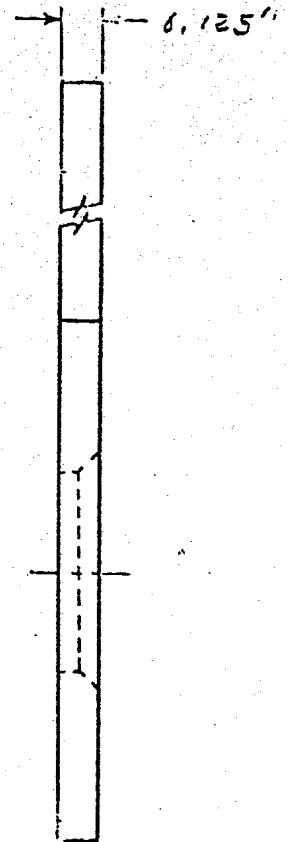
Furnish mfg. data	NUMBER OF COPIES		Type of Data	NUMBER OF COPIES			
in quantities ind:	W/Bid	30 Days	W/Equip.	(Continued)	W/Bid	30 Days	W/Equip.
1. Outlin dim. dwgs.	1		6	6. Test & Insp. Reports			
2. Oper. & Perf. data				7. Materials Cert.			
3. Lit. & Parts Lst.	1		6	8. Complete Schematics			
4. Oper. & Maint. Inst				9.			
5. Install. Instr.	1		6	10.			
PREPARED BY	SECTION (GROUP)		DIVISION (DEPT)	PRINCIPAL ENGR.	PROJECT ENGR. MANAGER		
J. Porras			O. J. Baker		D. G. Ailey		



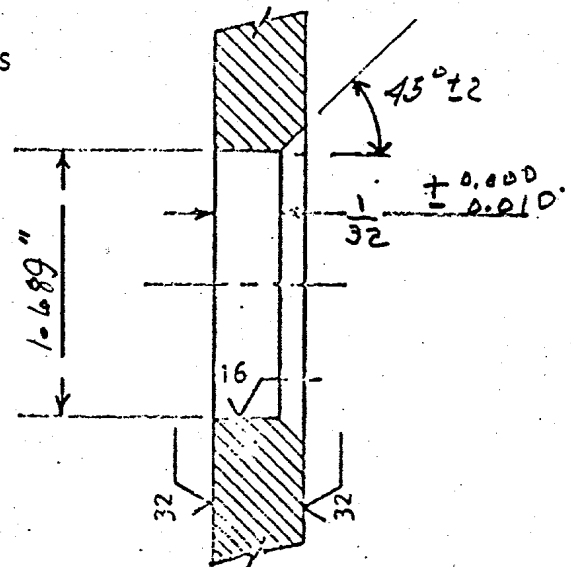
STAMP ON FACE OF PLATE

1. FE (EQUIPMENT NUMBER)
2. THE AVERAGE OF THREE BORE MEASUREMENTS TAKEN ON THREE DIAMETERS.

3. KDR FE-1026
FE-2026
D=1.689"



1. BORE TO BE SQUARE WITH FACES.
2. EDGES TO BE SHARP AND FREE FROM NICKS AND BURRS. NO ABRASIVES, INCLUDING CROCUS CLOTH, SHALL BE USED TO OBTAIN FINISH ON THE FACES OR INSIDE THE BORE OR TO REMOVE BURRS.
3. Add drain hole, per ISA-RP3.2



BORE DETAIL

ALL DIMENSIONS IN INCHES.
ALL DIMENSIONS $\pm 1/64$ INCH
UNLESS OTHERWISE SPECIFIED.

DATA SHEET		DATA SHEET NO.	REV.	ISSUE DATE
MARTIN MARIETTA ENERGY SYSTEMS, INC. OAK RIDGE, TN		DS-YIE-785-33	A	2-28-87
PROJECT TITLE		PAGE	OF	REQUISITION NO.
STEAM PLANT GAS IGNITION		1	3	
JOB TITLE		PROCURED BY	INSTALLED BY	
BURNER GAS FLOW		MM-ES	MM-ES	
EQUIPMENT		PROJECT NO.	E.S.O. OR W.O.	
FLOW ORIFICE PLATES, FE-1005 & FE-2005, FE-1005A, FE-2005A				

The following defines the technical requirements for an orifice plate.

1. General Requirements

Flow Rate: Per Table 1.
 Process Fluid: Natural Gas
 Process Temp.: 70°F
 Process Pressure: 39.6 psia
 Tagging: Metal tags to be attached to respective orifice plates, bearing the legend indicated on Table 1.
 Process pipe: 8"

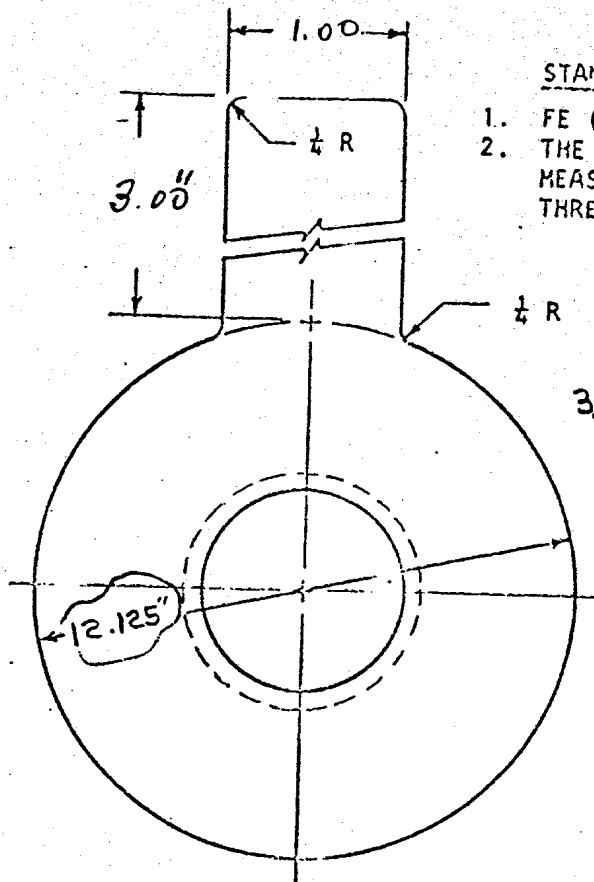
2. Orifice Plate

Material: 316 stainless steel
 Plate Thickness: 0.125"
 Class: ANSI: 300#
 Bore Size: Per Table 1
 Type: Paddle
 Orifice bore/line size (d/D): Per Table 1
 I.D: FE-1005, FE-2005, FE-1005A, FE-2005A

3. Table 1

Tag No.	Bore Size	Beta	P wc	Flow
FE-1005 & FE-2005	4.787"	0.599	129.6	0-450,000 scfh <i>main</i>
FE-1005A & FE-2005A	2.481"	0.310	25.0	0-50,000 scfh <i>not used</i>

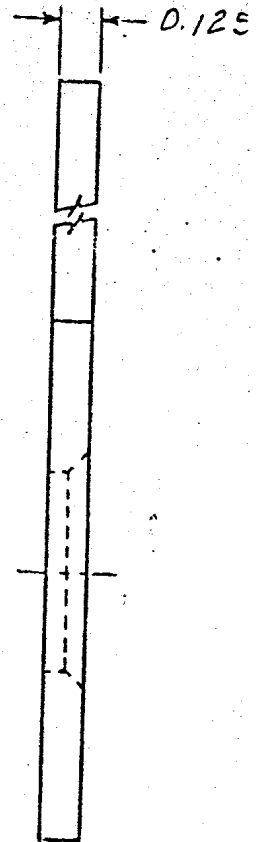
Furnish mfg. data	NUMBER OF COPIES		Type of Data	NUMBER OF COPIES	
in quantities ind:	W/Bid	30 Days	W/Equip.	(Continued)	W/Bid
1. Outlin. dwgs.	1		6	16. Test & Insp. Reports	
2. Oper. & Perf. data				17. Materials Cert.	
3. Lit. & Parts Lst.	1		6	18. Complete Schematics	
4. Oper. & Maint. Inst				19.	
5. Install. Instr.	1		6	10.	
PREPARED BY	SECTION (GROUP)	DIVISION (DEPT)	PRINCIPAL ENGR.	PROJECT ENGR. MANAGER	
J. Porras		Q. J. Baker	R. E. Berger	D. G. Ailey	



STAMP ON FACE OF PLATE

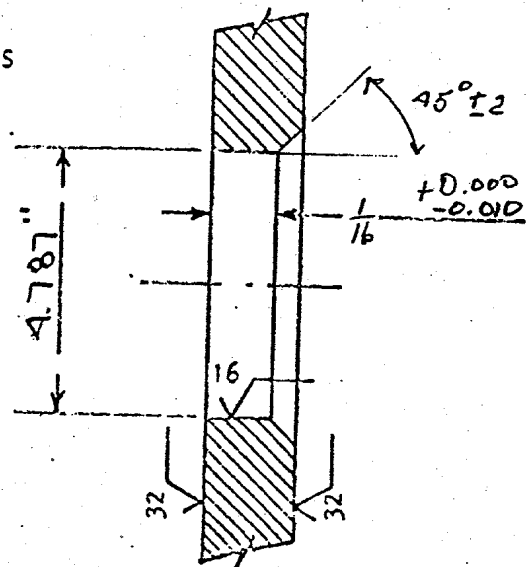
1. FE (EQUIPMENT NUMBER)
2. THE AVERAGE OF THREE BORE MEASUREMENTS TAKEN ON THREE DIAMETERS.

3. FE-1005, FE-2005



1. BORE TO BE SQUARE WITH FACES.
2. EDGES TO BE SHARP AND FREE FROM NICKS AND BURRS. NO ABRASIVES, INCLUDING CROCODUS CLOTH, SHALL BE USED TO OBTAIN FINISH ON THE FACES OR INSIDE THE BORE OR TO REMOVE BURRS.
3. Add drain hole, per ISA-RP3.2

ALL DIMENSIONS IN INCHES.
ALL DIMENSIONS $\pm 1/64$ INCH
UNLESS OTHERWISE SPECIFIED.



BORE DETAIL

VENDOR DESIGN INFORMATION

DATA SHEET MODEL 480V COALOMETER VOLUMETRIC

CUSTOMER — COMBUSTION ENG. INC. UNION CARBIDE CORP.

SERIAL NO 480V-15351/58

DESIGN CAPACITY — 12.1 STPH

DESIGN SPEED — 8.18 FT/MIN

DESIGN LOAD — 49.31 LB/FT

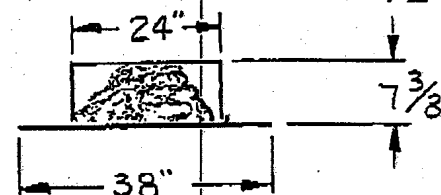
MATERIAL COAL

DENSITY 45-50 PCF

MOISTURE 5-8%

BELT WIDTH — 38"

BELT LENGTH — 11'-3 1/2"



$$\frac{\text{LB}}{\text{MIN}} \times \frac{\text{FT}}{\text{MIN}} = \text{LB/FT}$$

$$\frac{\text{LB/FT}}{\text{LB/FT}} = \text{FT/MIN}$$

$$\frac{1667 \text{ RPM}}{289 \text{ RATIO}} \times \frac{26 \text{ DRIVE}}{70 \text{ DRIVEN}} \times \frac{\text{SPRK.}}{3.82 \text{ FT/REV.}} = 8.18 \text{ FT/MIN (DESIGN)}$$

$$\frac{403.33 \text{ LB/MIN}}{8.18 \text{ FT/MIN}} = 49.31 \text{ LB/FT (DESIGN)}$$

MOTOR — 3/4 HP D.C. TENV DOUBLE ENDED SHAFT REDUCER H541A RATIO 289/1

~~LOAD CELL — TRANSDUCERS INC. MODEL G3H — CAPACITY~~

$$\frac{\text{LB/FT}}{\text{LB/FT}} \times 1.38 \text{ FT} \times 1.077 \times \frac{30}{500} = \text{MV}$$

ATTN: ROSCOE WILSON

TOTAL COAL PULSER

REGISTRATION — 20 LB
.01 TONS

$$403.3 \text{ LB/MIN. @ 20 LB. REG.} = .336 \text{ COUNTS/SEC.}$$

$$\frac{1667}{289} \times \frac{26}{70} \times \frac{14.25}{14} = 2.18 \text{ REV/MIN} \quad 2.18 \times \frac{1}{6} \times 120 \times \frac{1}{60} = .727 \text{ PP.}$$

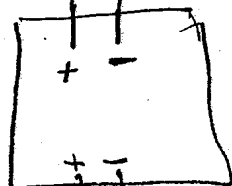
$$N = 01 \quad 3RM = .462$$

DATE 10-31-79

REV. Δ REVISED TOTAL COAL PULSER
1-13-80 T. S.

EXISTING
MOTOR
1720 RPM

TACH



WESTON
MODEL 750

TACHOMETER GENERATOR
TYPE A

SN: 114803

5 V - PER 1000 RPM

E/I CONVERTER

RIS - MOD. SC-1302-C

ISOLATED TRANSFORMER

0-10 VDC INPUT

4-20 MA OUTPUT

SN: 755271-1

4-20 mA OR 1-5 VOLTS

CALIBRATED METER 0-30,000 μ b/hr
0-15 TONS

Steam Plant Gas Flow Summer 9401-3

Manufacturer: Transmation Inc.

Model: 3940F: Adder/Subtractor 3940/ - /00/

Power Supply: 120 VAC

Inputs:

Two Inputs , 4-20ma, 120 VAC Supply.

- N1=4-20ma
- N2 = 4-20ma/ 4-20ma
- Input #1 0-450 X 1K cu. Ft/hr.
- Input #2 0-30 X 1K cu. Ft/hr

Outputs:

- 0-480 X 1K cu. Ft/hr.
(4-20ma into 600 ohms)

Connections:

Pins:

1	+ input #1
2	- input #1
3	+ input #2
4	- input #2
5	+ output
6	- output
7	+ input #3
8	- input #3
9	
10	AC (117 VAC +/- 10%)
11	N
12	GND

Calibration:

The calibration specifications as set by the factory are indicated on the data plate secured to the front panel inside the module.

INSTRUMENTATION THAT SETS THE TREND

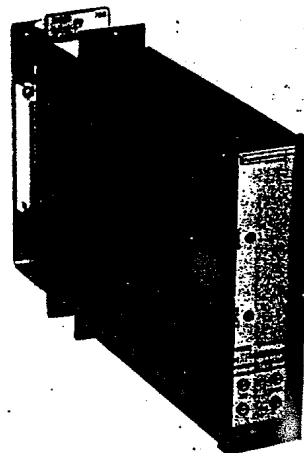


INSTRUCTION MANUAL

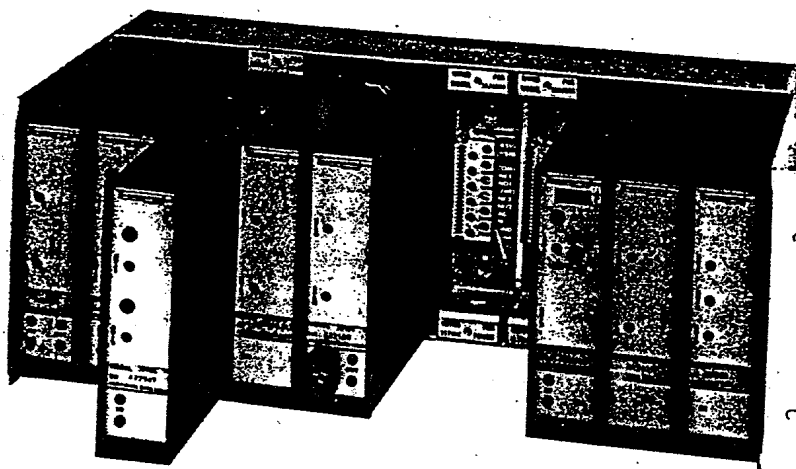
QUICK-CAL® 3000 FUNCTION MODULES

MODEL 3940F: ADDER / SUBTRACTER

Manual No.: 100658-911
Date: March, 1993
Supersedes: December, 1985
File: Analog



Any combination of Quick-Cal® 3000 transmitters, alarms and function modules may be mounted in a Transmation rack-frame Model 3010R.



INTERFACE INSTRUMENTATION - DIGITAL/ANALOG
Analysis • Specifications • Design • Production



977 MT. READ BLVD. □ P.O. BOX 7803 □ ROCHESTER, NEW YORK U.S.A. 14606

TELEX 97-8314 (TRANSMAT ROC) □ TELEPHONE (01) 716-254-9000

Attachment 6

Electronic Monitoring Plan MDL 4.1 EDR Printouts

Monitoring Plans

Unit 31

MONITORING PLAN
MONITORING DATA CHECKING SOFTWARE 4.1 BETA

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PAGE 1

FACILITY INFORMATION (RT 102)

=====

ORIS Code/Facility ID: 880055 EPA AIRS ID: State ID:

Plant Name: OAK RIDGE Y-12 State: TN Latitude: 355856 Longitude: 0841541

County Code: 001 County Name: ANDERSON Source Category/Type: INDUSTRIAL BOILER

Primary SIC Code/Description: 9999 Nonclassifiable Establishments

Add Quarter: 2003Q2

Update Quarter: 2003Q2

UNIT OPERATION INFORMATION (RT 504)

=====

Unit	Boiler	Max Heat	1st Comm	Retirement	Stack Exit	Stack Base	Area At	Area At	Non-Load-	
Unit ID	Short Name	Type	Input (mmBtu)	Operation Date	Date	Height	Elevation	Stack Exit	Flow Monitor	Based Unit
31	UNIT 31	WBF	296.8	04/16/1954	/ /	190	966	123	27	

=====

Boiler Type Codes: WBF - Wet bottom wall-fired

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
31	SUBH	B	OS	05/01/2003	1200327	TN

Unit Class Codes: B - Budget

Reporting Frequency Codes: OS - Ozone season

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility/ORISPL Number
31	31				N	

UNIT/STACK/PIPE ID: 31

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Stat.	ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Comp. ID	Stat.	Comp. Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	101	NOX	P	05/01/2003	/ /	118	A	NOX	DIN	API	200AH	UNKNOWN
						119	A	CO2	DIN	API	360	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	201	GAS	P	05/01/2003	/ /	152	A	GFFM	ORF	UNKNOWN	UNKNOWN	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	301	FLOW	P	05/01/2003	/ /	128	A	FLOW	U	MONITOR LABS	UF-150	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	501	NOXC	P	05/01/2003	/ /	118	A	NOX	DIN	API	200AH	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	601	CO2	P	05/01/2003	/ /	119	A	CO2	DIN	API	360	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN

Parameter Monitored Codes: CO2 - Carbon dioxide, FLOW - Stack Flow, GAS - Gas fuel flow, NOX - NOx emission rate, NOXC - NOx concentration

Primary/Backup Codes: P - Primary

Component Type Codes: CO2 - CO2 analyzer, DAHS - Data acquisition & handling system, FLOW - Stack Flow analyzer, GFFM - Gas fuel flowmeter, NOX - NOx analyzer

SAM codes: DIN - Dilution in-stack, ORF - Orifice, U - Ultrasonic

Status Codes: A - Add

Unit/Stack/Pipe ID: 31

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	001	HI	F-20	$HI_gas = (S\#(152 - 201) * GCV_gas) / 1000000$
A	002	HI	F-21	$HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000$
A	003	HI	D-15A	$HI_Total = F\#(001) + F\#(002)$
A	004	FC	F-8	$Fc = F\#(002) / F\#(003) * 1800 + F\#(001) / F\#(003) * 1040$
A	005	NOX	19-7	$E_h = 1.194 * 10^{** - 7} * S\#(118-101) * F\#(004) * (100 / S\#(119-101))$
A	006	NOXM	N-1	$NOx_Mass = 1.194 * 10^{** - 7} * S\#(118-101) * S\#(128-301) * T_31$

Status Codes: A - Add

Parameter Codes: FC - Carbon Based F-factor, HI - Heat input, NOX - NOx emission rate, NOXM - NOx mass emissions

SPAN VALUES (RT 530)

											Def.			
Unit/	Para-		Meth-	MPC/	Max.			Units		Inactive	Dual	High	Flow Rate	Flow Rate
Stk ID	meter	Sc.	od	MEC/	NOx		Full-Scale	of	Eff. Date	Date &	Spans	Range	Span Val.	Full Scale
				MPF	Rate	Span Value	Range	Meas.	and Hour	Hour	Req.	Value	In SCFH	In SCFH
=====														
31	CO2	H	TB	14.000		16.0	20.0	%	05/01/2003 01	/ /				
	FLOW	H	TR	4800000.000		100000	100000	SCFM	05/01/2003 01	/ /			6000000	6000000
	NOX	H	TB	800.000	3.400	800	1000	PPM	05/01/2003 01	/ /				

Parameter Codes: CO2 - Carbon dioxide, FLOW - Stack flow, NOX - NOx concentration

Scale Codes: H - High

Method Codes: TB - Table of Constants, TR - Test results

Units of Measure Codes: % - Percent, PPM - Parts per million, SCFM - Standard cubic feet per minute

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Three-load RATA Exemption Status
31	ST	250	

RANGE OF OPERATION, NORMAL OPERATING LEVEL AND OPERATING LEVEL USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Operating Levels	Designated Normal Op. Level	Second Designated Normal Op. Level	Activation Date	Deactivation Date
31	200	60	M,H	H		04/15/2003	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
31	201	GAS	PNG	4800	HSCF	URV	AGA3	A

Parameter Codes: GAS - Gas fuel flow
Fuel Type Codes: PNG - Pipeline natural gas
Units of Measure Codes: HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: URV - Upper Range Value
Submission Status Codes: A - Add

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
31	HI	AMS	C	P	SPTS	05/01/2003	/ /
	HI	GFF	PNG	P	SPTS	05/01/2003	/ /
	NOXM	CEM	NFS	P	SPTS	05/01/2003	/ /
	NOXR	CEM	NFS	P	SPTS	05/01/2003	/ /

Parameter Codes: HI - Heat Input, NOXM - NOx Mass Emissions, NOXR - NOx Emission Rate

Fuel Type Codes: C - Coal, NFS - Non-fuel specific, PNG - Pipeline natural gas

Methodology Codes: AMS - Alternative monitoring system, CEM - Continuous emission monitoring, GFF - Hourly gas flow

Missing Data Approach Codes: SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim- ization Date	Controls Retirement Date	Ozone Season Only?
31	PART	B	P		11/01/1984	05/01/2003	/ /	

Parameter Codes: PART - Particulates

Type of Controls Codes: B - Baghouse

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
31	C	P	05/01/2003	/ /			
	PNG	S	05/01/2003	/ /			

Fuel Classification Codes: C - Coal, PNG - Pipeline natural gas

Unit 32

MONITORING PLAN
MONITORING DATA CHECKING SOFTWARE 4.1 BETA

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FACILITY INFORMATION (RT 102)

=====

ORIS Code/Facility ID: 880055 EPA AIRS ID: State ID:

Plant Name: OAK RIDGE Y-12 State: TN Latitude: 355856 Longitude: 0841541

County Code: 001 County Name: ANDERSON Source Category/Type: INDUSTRIAL BOILER

Primary SIC Code/Description: 9999 Nonclassifiable Establishments

Add Quarter: 2003Q2

Update Quarter: 2003Q2

UNIT OPERATION INFORMATION (RT 504)

=====

Unit	Boiler	Max Heat	1st Comm	Retirement	Stack Exit	Stack Base	Area At	Area At	Non-Load-	
Unit ID	Short Name	Type	Input (mmBtu)	Operation Date	Date	Height	Elevation	Stack Exit	Flow Monitor	Based Unit
32	UNIT 32	WBF	296.8	04/16/1954	/ /	190	966	123	27	

=====

Boiler Type Codes: WBF - Wet bottom wall-fired

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
32	SUBH	B	OS	05/01/2003	1200327	TN

Unit Class Codes: B - Budget

Reporting Frequency Codes: OS - Ozone season

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility/ORISPL Number
32	32				N	

UNIT/STACK/PIPE ID: 32

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Stat.	ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Comp. ID	Stat.	Comp. Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	102	NOX	P	05/01/2003	/ /	122	A	NOX	DIN	API	200AH	UNKNOWN
						123	A	CO2	DIN	API	360	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	202	GAS	P	05/01/2003	/ /	153	A	GFFM	ORF	UNKNOWN	UNKNOWN	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	302	FLOW	P	05/01/2003	/ /	127	A	FLOW	U	MONITOR LABS	UF-150	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	502	NOXC	P	05/01/2003	/ /	122	A	NOX	DIN	API	200AH	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN
A	602	CO2	P	05/01/2003	/ /	123	A	CO2	DIN	API	360	UNKNOWN
						991	A	DAHS		ESC	8832	UNKNOWN

Parameter Monitored Codes: CO2 - Carbon dioxide, FLOW - Stack Flow, GAS - Gas fuel flow, NOX - NOx emission rate, NOXC - NOx concentration

Primary/Backup Codes: P - Primary

Component Type Codes: CO2 - CO2 analyzer, DAHS - Data acquisition & handling system, FLOW - Stack Flow analyzer, GFFM - Gas fuel flowmeter, NOX - NOx analyzer

SAM codes: DIN - Dilution in-stack, ORF - Orifice, U - Ultrasonic

Status Codes: A - Add

Unit/Stack/Pipe ID: 32

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	001	HI	F-20	$HI_gas = (S\#(153 - 202) * GCV_gas) / 1000000$
A	002	HI	F-21	$HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000$
A	003	HI	D-15A	$HI_Total = F\#(001) + F\#(002)$
A	004	FC	F-8	$Fc = F\#(002) / F\#(003) * 1800 + F\#(001) / F\#(003) * 1040$
A	005	NOX	19-7	$E_h = 1.194 * 10^{** - 7} * S\#(122-102) * F\#(004) * (100 / S\#(123-102))$
A	006	NOXM	N-1	$NOx_Mass = 1.194 * 10^{** - 7} * S\#(122-102) * S\#(127-302) * T_32$

Status Codes: A - Add

Parameter Codes: FC - Carbon Based F-factor, HI - Heat input, NOX - NOx emission rate, NOXM - NOx mass emissions

SPAN VALUES (RT 530)

											Def.			
Unit/	Para-		Meth-	MPC/	Max.			Units		Inactive	Dual	High	Flow Rate	Flow Rate
Stk ID	meter	Sc.	od	MEC/	NOx		Full-Scale	of	Eff. Date	Date &	Spans	Range	Span Val.	Full Scale
				MPF	Rate	Span Value	Range	Meas.	and Hour	Hour	Req.	Value	In SCFH	In SCFH
=====														
32	CO2	H	TB	14.000		16.0	20.0	%	05/01/2003 01	/ /				
	FLOW	H	TR	4800000.000		100000	100000	SCFM	05/01/2003 01	/ /			6000000	6000000
	NOX	H	TB	800.000	3.400	800	1000	PPM	05/01/2003 01	/ /				

Parameter Codes: CO2 - Carbon dioxide, FLOW - Stack flow, NOX - NOx concentration

Scale Codes: H - High

Method Codes: TB - Table of Constants, TR - Test results

Units of Measure Codes: % - Percent, PPM - Parts per million, SCFM - Standard cubic feet per minute

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Three-load RATA Exemption Status
32	ST	250	

RANGE OF OPERATION, NORMAL OPERATING LEVEL AND OPERATING LEVEL USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Operating Levels	Designated Normal Op. Level	Second Designated Normal Op. Level	Activation Date	Deactivation Date
32	200	60	M,H	H		04/16/2003	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
32	202	GAS	PNG	4800	HSCF	URV	AGA3	A

Parameter Codes: GAS - Gas fuel flow
Fuel Type Codes: PNG - Pipeline natural gas
Units of Measure Codes: HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: URV - Upper Range Value
Submission Status Codes: A - Add

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
32	HI	AMS	C	P	SPTS	05/01/2003	/ /
	HI	GFF	PNG	P	SPTS	05/01/2003	/ /
	NOXM	CEM	NFS	P	SPTS	05/01/2003	/ /
	NOXR	CEM	NFS	P	SPTS	05/01/2003	/ /

Parameter Codes: HI - Heat Input, NOXM - NOx Mass Emissions, NOXR - NOx Emission Rate

Fuel Type Codes: C - Coal, NFS - Non-fuel specific, PNG - Pipeline natural gas

Methodology Codes: AMS - Alternative monitoring system, CEM - Continuous emission monitoring, GFF - Hourly gas flow

Missing Data Approach Codes: SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim- ization Date	Controls Retirement Date	Ozone Season Only?
32	PART	B	P		11/01/1984	05/01/2003	/ /	

Parameter Codes: PART - Particulates

Type of Controls Codes: B - Baghouse

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
32	C	P	05/01/2003	/ /			
	PNG	S	05/01/2003	/ /			

Fuel Classification Codes: C - Coal, PNG - Pipeline natural gas

Unit 33

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MONITORING DATA CHECKING SOFTWARE 4.1 BETA

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FACILITY INFORMATION (RT 102)

=====

ORIS Code/Facility ID: 880055 EPA AIRS ID: State ID:

Plant Name: OAK RIDGE Y-12 State: TN Latitude: 355856 Longitude: 0841541

County Code: 001 County Name: ANDERSON Source Category/Type: INDUSTRIAL BOILER

Primary SIC Code/Description: 9999 Nonclassifiable Establishments

Add Quarter: 2003Q2

Update Quarter: 2003Q2

UNIT OPERATION INFORMATION (RT 504)

=====

Unit	Boiler	Max Heat	1st Comm	Retirement	Stack Exit	Stack Base	Area At	Area At	Non-Load-	
Unit ID	Short Name	Type	Input (mmBtu)	Operation Date	Date	Height	Elevation	Stack Exit	Flow Monitor	Based Unit
33	UNIT 33	WBF	297.0	04/16/1954	/ /	190	966	177	27	

=====

Boiler Type Codes: WBF - Wet bottom wall-fired

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
33	SUBH	B	OS	05/01/2003	1200327	TN

Unit Class Codes: B - Budget

Reporting Frequency Codes: OS - Ozone season

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility/ORISPL Number
33	33				N	

UNIT/STACK/PIPE ID: 33

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Stat.	ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Comp. ID	Stat.	Comp. Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	103	NOX	P	05/01/2003	/ /	218	A	NOX	DIN	API	200AH	UNKNOWN
						219	A	CO2	DIN	API	360	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	203	GAS	P	05/01/2003	/ /	252	A	GFFM	ORF	UNKNOWN	UNKNOWN	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	303	FLOW	P	05/01/2003	/ /	228	A	FLOW	U	MONITOR LABS	UF-150	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	503	NOXC	P	05/01/2003	/ /	218	A	NOX	DIN	API	200AH	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	603	CO2	P	05/01/2003	/ /	219	A	CO2	DIN	API	360	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN

Parameter Monitored Codes: CO2 - Carbon dioxide, FLOW - Stack Flow, GAS - Gas fuel flow, NOX - NOx emission rate, NOXC - NOx concentration

Primary/Backup Codes: P - Primary

Component Type Codes: CO2 - CO2 analyzer, DAHS - Data acquisition & handling system, FLOW - Stack Flow analyzer, GFFM - Gas fuel flowmeter, NOX - NOx analyzer

SAM codes: DIN - Dilution in-stack, ORF - Orifice, U - Ultrasonic

Status Codes: A - Add

Unit/Stack/Pipe ID: 33

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	001	HI	F-20	$HI_gas = (S\#(252 - 203) * GCV_gas) / 1000000$
A	002	HI	F-21	$HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000$
A	003	HI	D-15A	$HI_Total = F\#(001) + F\#(002)$
A	004	FC	F-8	$Fc = F\#(002) / F\#(003) * 1800 + F\#(001) / F\#(003) * 1040$
A	005	NOX	19-7	$E_h = 1.194 * 10^{** - 7} * S\#(218-103) * F\#(004) * (100 / S\#(219-103))$
A	006	NOXM	N-1	$NOx_Mass = 1.194 * 10^{** - 7} * S\#(218-103) * S\#(228-303) * T_33$

Status Codes: A - Add

Parameter Codes: FC - Carbon Based F-factor, HI - Heat input, NOX - NOx emission rate, NOXM - NOx mass emissions

SPAN VALUES (RT 530)

											Def.		
Unit/	Para-		Meth-	MPC/	Max.			Units	Inactive	Dual	High	Flow Rate	Flow Rate
Stk ID	meter	Sc.	od	MEC/	NOx		Full-Scale	of	Eff. Date	Date &	Spans	Span Val.	Full Scale
				MPF	Rate	Span Value	Range	Meas.	and Hour	Hour	Req.	In SCFH	In SCFH
=====													
33	CO2	H	TB	14.000		16.0	20.0	%	05/01/2003 01	/ /			
	FLOW	H	TR	4800000.000		100000	100000	SCFM	05/01/2003 01	/ /		6000000	6000000
	NOX	H	TB	800.000	3.400	800	1000	PPM	05/01/2003 01	/ /			

Parameter Codes: CO2 - Carbon dioxide, FLOW - Stack flow, NOX - NOx concentration

Scale Codes: H - High

Method Codes: TB - Table of Constants, TR - Test results

Units of Measure Codes: % - Percent, PPM - Parts per million, SCFM - Standard cubic feet per minute

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Three-load RATA Exemption Status
33	ST	250	

RANGE OF OPERATION, NORMAL OPERATING LEVEL AND OPERATING LEVEL USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Operating Levels	Designated Normal Op. Level	Second Designated Normal Op. Level	Activation Date	Deactivation Date
33	200	60	M,H	H		04/23/2003	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
33	203	GAS	PNG	4800	HSCF	URV	AGA3	A

Parameter Codes: GAS - Gas fuel flow
Fuel Type Codes: PNG - Pipeline natural gas
Units of Measure Codes: HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: URV - Upper Range Value
Submission Status Codes: A - Add

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
33	HI	AMS	C	P	SPTS	05/01/2003	/ /
	HI	GFF	PNG	P	SPTS	05/01/2003	/ /
	NOXM	CEM	NFS	P	SPTS	05/01/2003	/ /
	NOXR	CEM	NFS	P	SPTS	05/01/2003	/ /

Parameter Codes: HI - Heat Input, NOXM - NOx Mass Emissions, NOXR - NOx Emission Rate

Fuel Type Codes: C - Coal, NFS - Non-fuel specific, PNG - Pipeline natural gas

Methodology Codes: AMS - Alternative monitoring system, CEM - Continuous emission monitoring, GFF - Hourly gas flow

Missing Data Approach Codes: SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim- ization Date	Controls Retirement Date	Ozone Season Only?
33	PART	B	P		10/01/1985	05/01/2003	/ /	

Parameter Codes: PART - Particulates

Type of Controls Codes: B - Baghouse

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
33	C	P	05/01/2003	/ /			
	PNG	S	05/01/2003	/ /			

Fuel Classification Codes: C - Coal, PNG - Pipeline natural gas

Unit 34

MONITORING PLAN
MONITORING DATA CHECKING SOFTWARE 4.1 BETA

06/17/2003
PAGE 1

FACILITY INFORMATION (RT 102)

=====

ORIS Code/Facility ID: 880055 EPA AIRS ID: State ID:

Plant Name: OAK RIDGE Y-12 State: TN Latitude: 355856 Longitude: 0841541

County Code: 001 County Name: ANDERSON Source Category/Type: INDUSTRIAL BOILER

Primary SIC Code/Description: 9999 Nonclassifiable Establishments

Add Quarter: 2003Q2

Update Quarter: 2003Q2

UNIT OPERATION INFORMATION (RT 504)

=====

Unit	Boiler	Max Heat	1st Comm	Retirement	Stack Exit	Stack Base	Area At	Area At	Non-Load-	
Unit ID	Short Name	Type	Input (mmBtu)	Operation Date	Date	Height	Elevation	Stack Exit	Flow Monitor	Based Unit
34	UNIT 34	WBF	297.0	04/16/1954	/ /	190	966	177	27	

=====

Boiler Type Codes: WBF - Wet bottom wall-fired

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
34	SUBH	B	OS	05/01/2003	1200327	TN

Unit Class Codes: B - Budget

Reporting Frequency Codes: OS - Ozone season

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility/ORISPL Number
34	34				N	

UNIT/STACK/PIPE ID: 34

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Stat.	ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Comp. ID	Stat.	Comp. Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	104	NOX	P	05/01/2003	/ /	222	A	NOX	DIN	API	200AH	UNKNOWN
						223	A	CO2	DIN	API	360	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	204	GAS	P	05/01/2003	/ /	253	A	GFFM	ORF	UNKNOWN	UNKNOWN	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	304	FLOW	P	05/01/2003	/ /	227	A	FLOW	U	MONITOR LABS	UF-150	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	504	NOXC	P	05/01/2003	/ /	222	A	NOX	DIN	API	200AH	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN
A	604	CO2	P	05/01/2003	/ /	223	A	CO2	DIN	API	360	UNKNOWN
						993	A	DAHS		ESC	8832	UNKNOWN

Parameter Monitored Codes: CO2 - Carbon dioxide, FLOW - Stack Flow, GAS - Gas fuel flow, NOX - NOx emission rate, NOXC - NOx concentration

Primary/Backup Codes: P - Primary

Component Type Codes: CO2 - CO2 analyzer, DAHS - Data acquisition & handling system, FLOW - Stack Flow analyzer, GFFM - Gas fuel flowmeter, NOX - NOx analyzer

SAM codes: DIN - Dilution in-stack, ORF - Orifice, U - Ultrasonic

Status Codes: A - Add

Unit/Stack/Pipe ID: 34

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	001	HI	F-20	$HI_gas = (S\#(253 - 204) * GCV_gas) / 1000000$
A	002	HI	F-21	$HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000$
A	003	HI	D-15A	$HI_Total = F\#(001) + F\#(002)$
A	004	FC	F-8	$Fc = F\#(002) / F\#(003) * 1800 + F\#(001) / F\#(003) * 1040$
A	005	NOX	19-7	$E_h = 1.194 * 10^{** - 7} * S\#(222-104) * F\#(004) * (100 / S\#(223-104))$
A	006	NOXM	N-1	$NOx_Mass = 1.194 * 10^{** - 7} * S\#(222-104) * S\#(227-304) * T_34$

Status Codes: A - Add

Parameter Codes: FC - Carbon Based F-factor, HI - Heat input, NOX - NOx emission rate, NOXM - NOx mass emissions

SPAN VALUES (RT 530)

											Def.			
Unit/	Para-		Meth-	MPC/	Max.			Units		Inactive	Dual	High	Flow Rate	Flow Rate
Stk ID	meter	Sc.	od	MEC/	NOx		Full-Scale	of	Eff. Date	Date &	Spans	Range	Span Val.	Full Scale
				MPF	Rate	Span Value	Range	Meas.	and Hour	Hour	Req.	Value	In SCFH	In SCFH
=====														
34	CO2	H	TB	14.000		16.0	20.0	%	05/01/2003 01	/ /				
	FLOW	H	TR	4800000.000		100000	100000	SCFM	05/01/2003 01	/ /			6000000	6000000
	NOX	H	TB	800.000	3.400	800	1000	PPM	05/01/2003 01	/ /				

Parameter Codes: CO2 - Carbon dioxide, FLOW - Stack flow, NOX - NOx concentration

Scale Codes: H - High

Method Codes: TB - Table of Constants, TR - Test results

Units of Measure Codes: % - Percent, PPM - Parts per million, SCFM - Standard cubic feet per minute

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Three-load
			RATA Exemption Status
34	ST	250	

RANGE OF OPERATION, NORMAL OPERATING LEVEL AND OPERATING LEVEL USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Operating Levels	Designated Normal Op. Level	Second Designated Normal Op. Level	Activation Date	Deactivation Date
34	200	60	M,H	H		04/22/2003	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
34	204	GAS	PNG	4800	HSCF	URV	AGA3	A

Parameter Codes: GAS - Gas fuel flow
Fuel Type Codes: PNG - Pipeline natural gas
Units of Measure Codes: HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: URV - Upper Range Value
Submission Status Codes: A - Add

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
34	HI	AMS	C	P	SPTS	05/01/2003	/ /
	HI	GFF	PNG	P	SPTS	05/01/2003	/ /
	NOXM	CEM	NFS	P	SPTS	05/01/2003	/ /
	NOXR	CEM	NFS	P	SPTS	05/01/2003	/ /

Parameter Codes: HI - Heat Input, NOXM - NOx Mass Emissions, NOXR - NOx Emission Rate

Fuel Type Codes: C - Coal, NFS - Non-fuel specific, PNG - Pipeline natural gas

Methodology Codes: AMS - Alternative monitoring system, CEM - Continuous emission monitoring, GFF - Hourly gas flow

Missing Data Approach Codes: SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim- ization Date	Controls Retirement Date	Ozone Season Only?
34	PART	B	P		10/01/1985	05/01/2003	/ /	

Parameter Codes: PART - Particulates

Type of Controls Codes: B - Baghouse

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
34	C	P	05/01/2003	/ /			
	PNG	S	05/01/2003	/ /			

Fuel Classification Codes: C - Coal, PNG - Pipeline natural gas

Monitoring Plan Evaluation Reports

Unit 31

MONITORING DATA CHECKING SOFTWARE 4.1 BETA
MONITORING PLAN EVALUATION REPORT
2003 QUARTER 2

06/17/2003
PAGE 4

ORIS Code: 880055
Facility Name: OAK RIDGE Y-12

State: TN
County: ANDERSON

EVALUATION OF MONITORING PLAN DATA FOR UNIT 34

Record Types	Problem Number	Description
-----------------	-------------------	-------------

Based on the evaluation criteria in this version, the software
has not identified any errors for this unit.

Unit 32

MONITORING DATA CHECKING SOFTWARE 4.1 BETA
MONITORING PLAN EVALUATION REPORT
2003 QUARTER 2

06/17/2003
PAGE 2

ORIS Code: 880055
Facility Name: OAK RIDGE Y-12

State: TN
County: ANDERSON

EVALUATION OF MONITORING PLAN DATA FOR UNIT 32

Record Types	Problem Number	Description
-----------------	-------------------	-------------

Based on the evaluation criteria in this version, the software
has not identified any errors for this unit.

Unit 33

MONITORING DATA CHECKING SOFTWARE 4.1 BETA
MONITORING PLAN EVALUATION REPORT
2003 QUARTER 2

06/17/2003
PAGE 3

ORIS Code: 880055
Facility Name: OAK RIDGE Y-12

State: TN
County: ANDERSON

EVALUATION OF MONITORING PLAN DATA FOR UNIT 33

Record Types	Problem Number	Description
-----------------	-------------------	-------------

Based on the evaluation criteria in this version, the software
has not identified any errors for this unit.

Unit 34

MONITORING DATA CHECKING SOFTWARE 4.1 BETA
MONITORING PLAN EVALUATION REPORT
2003 QUARTER 2

06/17/2003
PAGE 4

ORIS Code: 880055
Facility Name: OAK RIDGE Y-12

State: TN
County: ANDERSON

EVALUATION OF MONITORING PLAN DATA FOR UNIT 34

Record Types	Problem Number	Description
-----------------	-------------------	-------------

Based on the evaluation criteria in this version, the software
has not identified any errors for this unit.

Electronic Data Reports

Unit 31

10088005522003V2.2

102OAK RIDGE Y-12

INDUSTRIAL BOILER 9999TN001 3558560841541

50431 WBF 296.819540416 190 966 123 27

50531 SUBH B OS200305011200327 TN

50631 31 N

51031 118101ANOX P NOX DINAPI 200AH UNKNOWN 20030501

51031 119101ANOX P CO2 DINAPI 360 UNKNOWN 20030501

51031 991101ANOX P DAHS ESC 8832 UNKNOWN 20030501

51031 152201AGAS P GFFMORFUNKNOWN UNKNOWN UNKNOWN 20030501

51031 991201AGAS P DAHS ESC 8832 UNKNOWN 20030501

51031 128301AFLOWP FLOWU MONITOR LABS UF-150 UNKNOWN 20030501

51031 991301AFLOWP DAHS ESC 8832 UNKNOWN 20030501

51031 118501ANOXCP NOX DINAPI 200AH UNKNOWN 20030501

51031 991501ANOXCP DAHS ESC 8832 UNKNOWN 20030501

51031 119601ACO2 P CO2 DINAPI 360 UNKNOWN 20030501

51031 991601ACO2 P DAHS ESC 8832 UNKNOWN 20030501

52031 A001HI F-20 HI_gas = (S#(152 - 201) * GCV_gas) / 1000000

52031 A002HI F-21 HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000

52031 A003HI D-15AHI Total = F#(001) + F#(002)

52031 A004FC F-8 Fc = F#(002) / F#(003) * 1800 + F#(001) / F#(003) * 1040

52031 A005NOX 19-7 E_h = 1.194 * 10 ** - 7 * S#(118-101) * F#(004) * (100 / S#(119-101))

52031 A006NOXMN-1 NOx Mass = 1.194 * 10 ** - 7 * S#(118-101) * S#(128-301) * T_31

53031 CO2 HTB 14.000 16.000 20.000% 03050101

53031 FLOWHTR 4800000.000 100000.000 100000.000SCFM 03050101 6000000 6000000

53031 NOX HTB 800.000 3.400 800.000 1000.000PPM 03050101

53531 ST 250

53631 200 60M,HH 20030415

54031 201GAS PNG 4800.0HSCF URVAGA3 A

58531 HI AMS C PSPTS 20030501

58531 HI GFF PNGPSPTS 20030501

58531 NOXMCEM NFSPPTS 20030501

58531 NOXRCEM NFSPPTS 20030501

58631 PARTB P 1984110120030501

58731 C 20030501 P

58731 PNG20030501 S

940CERTIFY Reed Leslie R 030617AAR

94101I am authorized to make this submission on behalf of the owners and

94102operators of the affected source or the affected units for which

94103the submission is made. I certify under penalty of law that I have

94104personally examined, and am familiar with, the statements and

94105information submitted in this document and all its attachments.

94106Based on my inquiry of those individuals with primary

94107responsibility for obtaining the information, I certify that the

94108statements and information are to the best of my knowledge and

94109belief true, accurate, and complete. I am aware that there are

94110significant penalties for submitting false statements and

94111information or omitting required statements and information,

94112including the possibility of fine or imprisonment.

Unit 32

10088005522003V2.2

102OAK RIDGE Y-12

INDUSTRIAL BOILER 9999TN001 3558560841541

50432 WBF 296.819540416 190 966 123 27

50532 SUBH B OS200305011200327 TN

50632 32 N

51032 122102ANOX P NOX DINAPI 200AH UNKNOWN 20030501

51032 123102ANOX P CO2 DINAPI 360 UNKNOWN 20030501

51032 991102ANOX P DAHS ESC 8832 UNKNOWN 20030501

51032 153202AGAS P GFFMORFUNKNOWN UNKNOWN UNKNOWN 20030501

51032 991202AGAS P DAHS ESC 8832 UNKNOWN 20030501

51032 127302AFLOWP FLOWU MONITOR LABS UF-150 UNKNOWN 20030501

51032 991302AFLOWP DAHS ESC 8832 UNKNOWN 20030501

51032 122502ANOXCP NOX DINAPI 200AH UNKNOWN 20030501

51032 991502ANOXCP DAHS ESC 8832 UNKNOWN 20030501

51032 123602ACO2 P CO2 DINAPI 360 UNKNOWN 20030501

51032 991602ACO2 P DAHS ESC 8832 UNKNOWN 20030501

52032 A001HI F-20 HI_gas = (S#(153 - 202) * GCV_gas) / 1000000

52032 A002HI F-21 HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000

52032 A003HI D-15AHI Total = F#(001) + F#(002)

52032 A004FC F-8 Fc = F#(002) / F#(003) * 1800 + F#(001) / F#(003) * 1040

52032 A005NOX 19-7 E_h = 1.194 * 10 ** - 7 * S#(122-102) * F#(004) * (100 / S#(123-102))

52032 A006NOXMN-1 NOx Mass = 1.194 * 10 ** - 7 * S#(122-102) * S#(127-302) * T_32

53032 CO2 HTB 14.000 16.000 20.000% 03050101

53032 FLOWHTR 4800000.000 100000.000 100000.000SCFM 03050101 6000000 6000000

53032 NOX HTB 800.000 3.400 800.000 1000.000PPM 03050101

53532 ST 250

53632 200 60M,HH 20030416

54032 202GAS PNG 4800.0HSCF URVAGA3 A

58532 HI AMS C PSPTS 20030501

58532 HI GFF PNGPSPTS 20030501

58532 NOXMCEM NFSPPTS 20030501

58532 NOXRCEM NFSPPTS 20030501

58632 PARTB P 1984110120030501

58732 C 20030501 P

58732 PNG20030501 S

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Unit 33

10088005522003V2.2

102OAK RIDGE Y-12

INDUSTRIAL BOILER 9999TN001 3558560841541

50433 WBF 297.019540416 190 966 177 27

50533 SUBH B OS200305011200327 TN

50633 33 N

51033 218103ANOX P NOX DINAPI 200AH UNKNOWN 20030501

51033 219103ANOX P CO2 DINAPI 360 UNKNOWN 20030501

51033 993103ANOX P DAHS ESC 8832 UNKNOWN 20030501

51033 252203AGAS P GFFMORFUNKNOWN UNKNOWN UNKNOWN 20030501

51033 993203AGAS P DAHS ESC 8832 UNKNOWN 20030501

51033 228303AFLOWP FLOWU MONITOR LABS UF-150 UNKNOWN 20030501

51033 993303AFLOWP DAHS ESC 8832 UNKNOWN 20030501

51033 218503ANOXCP NOX DINAPI 200AH UNKNOWN 20030501

51033 993503ANOXCP DAHS ESC 8832 UNKNOWN 20030501

51033 219603ACO2 P CO2 DINAPI 360 UNKNOWN 20030501

51033 993603ACO2 P DAHS ESC 8832 UNKNOWN 20030501

52033 A001HI F-20 HI_gas = (S#(252 - 203) * GCV_gas) / 1000000

52033 A002HI F-21 HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000

52033 A003HI D-15AHI Total = F#(001) + F#(002)

52033 A004FC F-8 Fc = F#(002) / F#(003) * 1800 + F#(001) / F#(003) * 1040

52033 A005NOX 19-7 E_h = 1.194 * 10 ** - 7 * S#(218-103) * F#(004) * (100 / S#(219-103))

52033 A006NOXMN-1 NOx Mass = 1.194 * 10 ** - 7 * S#(218-103) * S#(228-303) * T_33

53033 CO2 HTB 14.000 16.000 20.000% 03050101

53033 FLOWHTR 4800000.000 100000.000 100000.000SCFM 03050101 6000000 6000000

53033 NOX HTB 800.000 3.400 800.000 1000.000PPM 03050101

53533 ST 250

53633 200 60M,HH 20030423

54033 203GAS PNG 4800.0HSCF URVAGA3 A

58533 HI AMS C PSPTS 20030501

58533 HI GFF PNGPSPTS 20030501

58533 NOXMCEM NFSPPTS 20030501

58533 NOXRCEM NFSPPTS 20030501

58633 PARTB P 1985100120030501

58733 C 20030501 P

58733 PNG20030501 S

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Unit 34

10088005522003V2.2

102OAK RIDGE Y-12

INDUSTRIAL BOILER 9999TN001 3558560841541

50434 WBF 297.019540416 190 966 177 27

50534 SUBH B OS200305011200327 TN

50634 34 N

51034 222104ANOX P NOX DINAPI 200AH UNKNOWN 20030501

51034 223104ANOX P CO2 DINAPI 360 UNKNOWN 20030501

51034 993104ANOX P DAHS ESC 8832 UNKNOWN 20030501

51034 253204AGAS P GFFMORFUNKNOWN UNKNOWN UNKNOWN 20030501

51034 993204AGAS P DAHS ESC 8832 UNKNOWN 20030501

51034 227304AFLOWP FLOWU MONITOR LABS UF-150 UNKNOWN 20030501

51034 993304AFLOWP DAHS ESC 8832 UNKNOWN 20030501

51034 222504ANOXCP NOX DINAPI 200AH UNKNOWN 20030501

51034 993504ANOXCP DAHS ESC 8832 UNKNOWN 20030501

51034 223604ACO2 P CO2 DINAPI 360 UNKNOWN 20030501

51034 993604ACO2 P DAHS ESC 8832 UNKNOWN 20030501

52034 A001HI F-20 HI_gas = (S#(253 - 204) * GCV_gas) / 1000000

52034 A002HI F-21 HI_coal = ((coal_1 + coal_2) * GCV_coal) / 1000000

52034 A003HI D-15AHI Total = F#(001) + F#(002)

52034 A004FC F-8 Fc = F#(002) / F#(003) * 1800 + F#(001) / F#(003) * 1040

52034 A005NOX 19-7 E_h = 1.194 * 10 ** - 7 * S#(222-104) * F#(004) * (100 / S#(223-104))

52034 A006NOXMN-1 NOx Mass = 1.194 * 10 ** - 7 * S#(222-104) * S#(227-304) * T_34

53034 CO2 HTB 14.000 16.000 20.000% 03050101

53034 FLOWHTR 4800000.000 100000.000 100000.000SCFM 03050101 6000000 6000000

53034 NOX HTB 800.000 3.400 800.000 1000.000PPM 03050101

53534 ST 250

53634 200 60M,HH 20030422

54034 204GAS PNG 4800.0HSCF URVAGA3 A

58534 HI AMS C PSPTS 20030501

58534 HI GFF PNGPSPTS 20030501

58534 NOXMCEM NFSPPTS 20030501

58534 NOXRCEM NFSPPTS 20030501

58634 PARTB P 1985100120030501

58734 C 20030501 P

58734 PNG20030501 S

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Attachment 7
Certification Test Protocol

**Continuous Emissions Monitoring System
Certification Test Protocol
for the**

**Y-12 Steam Plant
ORIS Number 880055**

**Y-12 National Security Complex
Oak Ridge, Tennessee**

Prepared by



**URS Group, Inc.
1093 Commerce Park Drive, Suite 100
Oak Ridge, TN 37830**

**February 2003
Client Subcontract No. 4300019834
URS Project No. 809930**

**Continuous Emissions Monitoring System
Certification Test Protocol
for the
Y-12 Steam Plant
ORIS Number 880055**

**Y-12 National Security Complex
Oak Ridge, Tennessee**

February 2003
Doc. # 0210081

Prepared by

URS Group, Inc.
1093 Commerce Park Drive, Suite 100
Oak Ridge, Tennessee 37830



Client Subcontract No. 4300019834
URS Project No. 809930

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ACRONYMS

CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO ₂	Carbon Dioxide
DAHS	Data Acquisition and Handling System
EGU	Electrical Generating Unit
EPA	U.S. Environmental Protection Agency
ESC	Environmental Systems Corporation
NO ₂	Nitrogen Dioxide
NO	Nitric Oxide
NO _x	Nitrogen Oxides
O ₃	Ozone
ppm	parts per million
QA	Quality Assurance
QC	Quality Control
RA	Relative Accuracy
RATA	Relative Accuracy Test Audit
SIP	State Implementation Plan
TDEC	Tennessee Department of Environment and Conservation
URS	URS Group, Inc.
Y-12	Y-12 National Security Complex

1. INTRODUCTION

The Oak Ridge Y-12 National Security Complex (Y-12), managed by BWXT, is submitting this Certification Test Protocol in conformance with the requirements of Title 40 of the U.S. Code of Federal Regulations (CFR) Part 75. The state of Tennessee identified the Y-12 Steam Plant in Oak Ridge, Tennessee, as a non-electrical generation unit (EGU) nitrogen oxides (NO_x) budget source as a result of the NO_x State Implementation Plan (SIP) under the Tennessee Department of Environment and Conservation (TDEC) Rule 1200-3-27.

The Y-12 Steam Plant consists of four Wickes boilers. Each has a nameplate steam production capacity of 250,000 lb/hour. The boilers are used to supply steam for building heating and cooling, and the steam rate during ozone season (May 1 – September 30) typically ranges from 60,000 to 200,000 lb/hour. Although pulverized coal is the principal fuel, each of the units can fire natural gas or a combination of coal and gas. Each unit is equipped with a Joy Manufacturing Company reverse air baghouse to control particulate emissions. Flue gases travel out of the baghouse, through an induced draft fan, then to one of two stacks. Boilers 1 and 2 exhaust through Stack 1. Boilers 3 and 4 exhaust through Stack 2.

A dedicated CEMS will be installed in the ductwork of each boiler, downstream of the baghouse. The CEMS will be designed, built, installed, and started up by URS Group, Inc. (URS). Data acquisition and handling is accomplished utilizing a data acquisition and handling system (DAHS) designed, built, and programmed by Environmental Systems Corporation (ESC). The installed CEMS will continuously monitor NO_x, flue gas flowrate, and carbon dioxide (CO₂). The CEMS will be utilized to report emissions from each unit for each ozone season starting May 1, 2003. This system is described in more detail in the CEMS Monitoring Plan.

Attachments 1–5 to the Monitoring Plan are also applicable to this Certification Test Protocol. Attachment 1 is a schematic diagram of the boilers. Attachment 2 shows a layout of the system with the CEMS components at the ducts, the CEM shelters, and the sampling ports. Attachment 2 also shows the distances to upstream and downstream disturbances. Attachment 3 is a schematic data flow diagram for Boilers 1 and 2 and the equipment in CEM Shelter 1. The diagram shows the piping/tubing connections, wiring connections, and inputs to the DAHS from the boiler control rooms. The same information is shown in Attachment 4 for Boilers 3 and 4 and CEM Shelter 2.

Opacity is currently monitored in each stack. The requirement for opacity monitoring is not required by the NO_x SIP program (TDEC Rule 1200-3-27) but as a condition of the Tennessee operating permit. The existing opacity monitors will be replaced by new units at the location of the existing monitors. The new opacity monitors will meet the requirements of 40 CFR 60, Appendix B and TDEC Rule 1200-3-10. Opacity will be monitored year-around.

This test plan documents the testing procedures and quality assurance (QA)/quality control (QC) requirements for performing initial certification testing of the CEMS. This testing is required by 40 CFR 75, Subpart C, and will demonstrate that the CEMS meets the specifications of 40 CFR 75, Appendix A. Testing procedures will comply with applicable U.S. Environmental Protection Agency (EPA) methods and follow the required QA/QC procedures. A final report documenting the results of the certification testing and the application for CEMS certification will be submitted to EPA's Clean Air Markets Division, EPA Region IV, and TDEC within 45 days of test completion.

1.1 PROPOSED TEST SCHEDULE

There are two phases of certification testing. In the first phase, the CEMS demonstrates that they are operational as installed. These tests include a demonstration of linearity, response time, and calibration drift over a 7-day period. This operational test phase is scheduled for the first week of a 2-week test period. In the second phase, the CEMS demonstrate that their measurements are representative by comparing their results to reference tests. The primary tests during this phase are Relative Accuracy Test Audits (RATAs). These tests are scheduled for the second week.

2. INSTALLED CEMS DESCRIPTION

The CEMS are designed to continuously measure NO_x, CO₂, opacity, and flow in the exhaust gases. The CEMS includes a sample transport system, the analyzers, and a DAHS for data collection, storage, and calibrations. The DAHS also performs the necessary calculations to determine emission rates and generate the required regulatory reports.

A sample of flue gas is extracted by a dilution probe. The sample is diluted with dry gas and transported to the analyzers. Using this approach, the sample is on a “wet basis” since the moisture in the flue gas is not condensed in the sampling system. The flue gas flowrate is measured at virtually the same location. The reference method ports where certification tests will be performed are also near the location of the probe and flow monitors.

The opacity monitors are located in the stacks approximately 80 ft above grade. Although opacity monitoring is not part of the NO_x monitoring system, the DAHS also collects and reports opacity data.

Attachment 2 shows a layout of the system with the CEMS components at the ducts, the CEM shelters, and the sampling ports. Attachment 2 also shows the distances to upstream and downstream disturbances. Attachment 3 is a schematic data flow diagram for Boilers 1 and 2 and the equipment in CEM Shelter 1. The same information is shown in Attachment 4 for Boilers 3 and 4 and CEM Shelter 2.

The analyzers continuously measure NO_x, CO₂, flow, and opacity. Details on each analyzer are presented in Table 2.1.

Table 2.1. CEM analyzer specifications

Parameter	Analyzer	Principal of operation	Daily span
NO _x	API Model 200AH	Chemiluminescence	800 parts per million (ppm)
CO ₂	API Model 360	Gas filter correlation	16%
Flue gas flow	Monitor Labs Ultraflow 150	Ultrasonic	100% of scale ^a
Opacity	Monitor Labs Model LH-560	Double pass extinction	100%

^a Equivalent to 3,700 wsft/min and 6,000,000 scfh

The DAHS Model 8832 manufactured by ESC continuously records and stores emissions data and also controls automatic system features such as calibrations. The DAHS records and stores the emission parameters for NO_x, CO₂, flue gas flow, and opacity. The computer calculates emission rates, estimates missing data, and generates quarterly reports.

3. CERTIFICATION TEST PROCEDURES

This section describes the test methods that will be used to demonstrate that the CEMS operate in accordance with regulatory requirements. The initial certification requirements for each type of CEMS monitor are listed in 40 CFR 75.20(c). The field performance specifications for the opacity monitors are listed in 40 CFR 60, Appendix B, Performance Specification 1 (PS-1). This section discusses boiler operating ranges (Sect. 3.1), NO_x budget CEMS (Sect. 3.2), opacity monitor (Sect. 3.3), test strategy (Sect. 3.4), DAHS (Sect. 3.5), and test report documentation (Sect. 3.6).

3.1 BOILER OPERATING RANGES

The nameplate capacity of each of the boilers is 250,000 lb steam/hour. However, since the boilers are used primarily to supply steam for building environmental controls, the steam rate during ozone season (May 1–September 30) typically ranges from 60,000 to 200,000 lb/hour. The lower boundary of the range of operation is the lowest minimum safe, stable load. The upper boundary of the range of operation is the maximum load that can be sustained during ozone season. Therefore, the target ranges for the certification tests are listed in Table 3.1.

Table 3.1. Boiler operating ranges for certification tests

Operating range	Steam load
High (normal load for initial period)	144,000–200,000 lb/hour
Mid	102,000–144,000 lb/hour
Low	60,000–102,000 lb/hour

High load is designated the normal range for the initial period. For future RATAs, normal load will be identified based on the operating history of the units, as defined in 40 CFR 75, Appendix A, Sect. 6.5.2.1.

3.2 NO_x BUDGET CEMS

The initial certification tests for CEMS required under the NO_x Budget are found in 40 CFR 75, Appendix A, Sect. 6 and the associated performance specifications are found in 40 CFR 75, Appendix A, Sect. 3. The operational and accuracy tests to be performed are summarized in Table 3.2.

Table 3.2. CEMS initial certification tests

CEMS monitor	Linearity check	7-day calibration error	Cycle time	RATA	Bias	Reference flow-to-load
NO _x	✓	✓	✓	✓	✓	
CO ₂	✓	✓	✓	✓		
Flue gas flow		✓		✓	✓	✓

3.2.1 NO_x and CO₂ Monitors

3.2.1.1 Linearity Check

A linearity check verifies the linear response of each monitor across a range of inputs. A linearity check is performed by challenging the gas monitor with low-, mid-, and high-level calibration gases. Calibration gases will be introduced into the dilution probe chamber, upstream of the critical orifice. This is the same location where flue gas enters the sampling system during normal CEMS operation. The percentage linearity error, LE, is calculated for each reference value calibration gas according to the following formula:

$$LE = 100 \times (\text{Reference Value} - \text{CEMS response}) / \text{Reference Value}$$

where the CEMS response is the average of three responses. For NO_x monitors, LE must be $\leq 5.0\%$ or have a difference in measured values ≤ 5 ppm. For CO₂ monitors, LE must $\leq 5.0\%$ or have a difference in measured values $\leq 0.5\%$ CO₂.

Calibration gas concentrations, based on 40 CFR 75, Appendix A, Sect. 5 are summarized in Table 3.3.

Table 3.3. Span and linearity check concentrations

Analyzer	Daily span	Concentrations for linearity check		
		Low	Mid	High
NO _x	800 ppm	160–240 ppm	400–480 ppm	640–800 ppm
CO ₂	16%	3–5%	8–10%	13–16%

3.2.1.2 7-Day Calibration Error Test

Calibration error testing verifies the stability of the CEMS over a period of time. A calibration error test is performed by challenging the gas monitor with low- and high-level calibration gases once every 24 hours for a period of 7 days. Calibration error, CE, for each reference value calibration gas is defined according to the following formula:

$$CE = 100 * (\text{Reference Value} - \text{CEMS response}) / \text{Instrument Span}$$

Each gas monitor is challenged only once with each calibration gas. No unscheduled maintenance, repair, or adjustments may take place between calibration gas injections. Note that a mid-level calibration gas may be used in lieu of the high-level calibration gas if that concentration is more representative of the actual stack gas conditions. For the NO_x monitor, CE must $\leq 2.5\%$. For the CO₂ monitor, the absolute value of the reference value calibration gas minus the monitor response must be $\leq 2.5\%$ or have a difference in measured values $\leq 0.5\%$ CO₂.

3.2.1.3 Cycle Time Test

The cycle time test measures the CEMS response to a step input change. A cycle time test is performed by introducing zero- and high-level calibration gases. Both upscale and downscale elapsed times are measured with the longest time being reported as the cycle time. The upscale elapsed time is the time it takes for the gas monitor to register 95.0% of the step change between a stable starting gas value (achieved by injecting zero-level calibration gas) and a stable ending gas value (achieved by injecting stack gas). The downscale elapsed time is the time it takes for the gas monitor to register 95.0% of the step change between a stable starting gas value (achieved by injecting high-level calibration gas) and a

stable ending gas value (achieved by injecting stack gas). A stable value changes less than 2% of the span for 2 minutes. For the NO_x and CO₂ monitors, the cycle time must not exceed 15 minutes.

3.2.1.4 Relative Accuracy Test Audit

A RATA verifies the accuracy of the CEMS by comparing their measurements with measurements obtained simultaneously by separate, calibrated reference method analyzers. The reference method analyzers are operated in accordance with 40 CFR 60, Appendix A, Method 7E for NO_x, and 40 CFR 60, Appendix A, Method 3A for CO₂. The reference method measurement locations are the sample ports shown in Attachment 2. These locations and the measurement points will meet the specifications in 40 CFR 75, Appendix A and 40 CFR 60, Appendix A.

For NO_x and CO₂ the RATA will be performed at normal operating load. For the initial RATA, the normal load level will be the high load as identified in Table 3.1. For future RATAs, normal load will be identified based on the operating history of the units, as defined in 40 CFR 75, Appendix A, Sect. 6.5.2.1.

A RATA requires a minimum of nine individual reference method sampling periods. More than nine runs may be conducted and up to three runs may be rejected. All data, including the rejected data, must be reported. Each sampling period must be at least 21 minutes in duration. The gas monitor and reference method results will be reported in the same units (i.e., NO_x ppm and CO₂ %) on a consistent basis for moisture, pressure, temperature, and diluent concentration.

The mean difference, standard deviation of the differences, and confidence coefficient between the CEMS and reference method data are used to calculate the relative accuracy, RA. The required equations are shown below:

Arithmetic Mean: Calculate the arithmetic mean of the difference of a data set as follows.

$$\bar{d} = \frac{1}{n} \sum_{i=1}^n d_i$$

where:

n = number of data points,

$\sum_{i=1}^n d_i$ = Algebraic sum of the individual differences d_i.

Standard Deviation: Calculate the standard deviation, S_d, as follows:

$$S_d = \left[\frac{\sum_{i=1}^n d_i^2 - \frac{\left(\sum_{i=1}^n d_i \right)^2}{n}}{n-1} \right]^{1/2}$$

Confidence Coefficient: Calculate the 2.5% error confidence coefficient (one-tailed), CC, as follows:

$$CC = t_{0.975} \frac{S_d}{\sqrt{n}}$$

where: $t_{0.975}$ = t-value (see Table 3.4).

Table 3.4. t-Values

N^a	$t_{0.975}$	N^a	$t_{0.975}$	N^a	$t_{0.975}$
2	12.706	7	2.447	12	2.201
3	4.303	8	2.365	13	2.179
4	3.182	9	2.306	14	2.160
5	2.776	10	2.262	15	2.145
6	2.571	11	2.228	16	2.131

^a The t-Values are already corrected for n-1 degrees of freedom.
Use n equal to the number of individual values.

Relative Accuracy: Calculate the RA of a set of data as follows:

$$RA = \frac{|\bar{d}| + |CC|}{\overline{RM}} \times 100\%$$

where:

$|\bar{d}|$ = Absolute value of the mean of differences,

$|CC|$ = Absolute value of the confidence coefficient,

\overline{RM} = Average reference method value.

For NO_x monitors, RA must be ≤ 10.0%. For CO₂ monitors, RA must be ≤ 10.0% or have a measured value difference of ≤ 1% CO₂

3.2.1.5 Bias Check

The bias check for the NO_x gas monitor uses data from the RATAs. If the absolute value of the mean differences is greater than the absolute value of the confidence coefficient, the gas monitor has failed the bias check. If the gas monitor fails the bias check, then the monitor outputs must be adjusted by the bias adjustment factor defined by Equation A-12 in 40 CFR 75, Appendix A, Sect. 7.6.5(a).

3.2.2 Flow Monitor

The initial certification tests for a flow monitor include a 7-day calibration error test, a flow RATA, and a bias check. A reference flow-to-load test is also required.

The 7-day CALIBRATION ERROR TEST for the flow monitor is similar to that for the gas monitors described above and verifies the stability of the flow monitor over a period of time. A calibration error test is performed by challenging the flow monitor once every 24 hours for a period of 7 days. However, instead of using calibration gases as the monitor input, reference electrical signals are input directly to the transducer. The Ultraflow 150 performs this calibration check automatically by injecting precise phase-shifted frequency pairs that represent approximately 0% and 100% of instrument span. The flow monitor is challenged only once with each reference signal. No unscheduled maintenance, repair, or adjustments may take place between reference signal inputs. For the flow monitor, CE must be $\leq 3.0\%$.

The flow monitor RATA is similar to that for the gas monitors described above except three different load conditions are required (refer to Table 3.1). One set of RATAs will be performed along with the NO_x and CO₂ monitor RATAs at high load. Additional RATAs, for flow only, will be performed at the mid and low loads. Flow will be simultaneously measured by the CEMS flow monitor and by 40 CFR 60, Appendix A, Method 2. Traverse points will be selected in accordance with 40 CFR 60, Appendix A, Method 1. The RATA will consist of at least nine test runs for each load condition. The flow monitor bias check calculation is identical to that for the NO_x and CO₂ gas monitors, as described in Sect. 3.2.1.5. The RA must be $\leq 10.0\%$, or if the velocity is less than 10 ft/sec, the reference and CEM velocities must be within 2 ft/sec.

3.2.2.1 Reference Flow-to-Load Ratio

The velocity traverse data from 40 CFR 60, Appendix A, Method 2 used for the flow monitor RATAs will be used to calculate the reference flow-to-load ratio under the normal load condition. The reference flow-to-load ratio will be calculated using the following equation:

$$R_{\text{ref}} = Q_{\text{ref}} \times 10^{-5} / L_{\text{av}}$$

where:

R_{ref} = reference flow-to-load ratio (scfh/1,000 lb/hour steam),

Q_{ref} = average volumetric flow during normal load RATA (scfh),

L_{av} = average load during the normal load flow RATA (1,000 lb steam/hour).

This value will be incorporated into the electronic Monitoring Plan.

3.3 OPACITY MONITOR

The initial certification tests for the opacity monitor are detailed in PS-1. PS-1 lists requirements for opacity monitor manufacturers as well as opacity monitor owners and operators. The manufacturer has complied with the requirements to certify the design of the opacity monitor. The opacity monitor certificate of conformance will be included in the certification test report. The field audit tests include an optical alignment assessment, a calibration error check, a system response time check, and an averaging period calculation and recording check. Also, during the 168-hour operational test period, the 24-hour zero drift check and 24-hour calibration drift check must be recorded. Each of these audit requirements is described below.

Optical Alignment. Across stack alignment of the optical head assembly and reflector assembly will be confirmed using the optical alignment sight on the monitor. Adjustments will be made as necessary.

Calibration Error. Calibration error will be determined from a three-point calibration test using three calibration attenuators representing low-, mid-, and high-level opacities. Five nonconsecutive readings for each attenuator will be recorded. The calibration error for each of the three attenuators will be reported as the sum of the absolute value of the mean differences and the confidence coefficient.

System Response Time. The system response time is the amount of time for the system to respond to a 95% step change in opacity. The upscale response time is the amount of time required for the system to stabilize and record a 95% change in opacity after insertion of the high-level calibration attenuator. The downscale response time is the amount of time required for the system to stabilize and record 5% of the initial opacity reading after the removal of the high-level calibration attenuator. The average of five upscale response times and the average of five downscale response times will be reported.

Averaging Period Calculation and Recording. Each calibration attenuator is inserted for a period of two times the averaging period plus 1 minute. The attenuator opacity value is compared to the average value calculated by the monitor for each attenuator.

24-hour Drift. The zero and upscale responses from the monitor's automated calibration check system for each 24-hour period will be compared to the simulated values to obtain the 24-hour drift. The 24-hour drift error for both zero and upscale responses will be reported as the sum of the absolute value of the mean differences and the confidence coefficient.

Table 3.5 lists the performance specifications for the opacity monitor.

Table 3.5. Opacity monitor performance specifications

Parameter	Specification
Calibration error	$\leq 3\%$ Opacity
Response time	≤ 10 seconds
Averaging period calculation	$\pm 2\%$ Opacity
24-hour zero drift	$\leq 2\%$ Opacity
24-hour Calibration Drift	$\leq 2\%$ Opacity

3.4 TEST STRATEGY

The certification tests will be performed over a 2-week period. The operational tests will be performed during the first week on all the monitors. For the NO_x , CO_2 , and flue gas flow monitors, this will include calibration drift over a 7-day period.

The RATAs and opacity monitor field audits will be performed during the second week. A sample schedule is shown below.

- **Day 1:** The load will have been increased on Boiler A until stable operation is achieved at high load (refer to Table 3.1). NO_x , CO_2 , and flue gas flow RATAs will be performed simultaneously on Boiler A. When these tests have been successfully completed, the boiler load will be decreased to the mid range for the next flue gas flow RATA. Testing will be concluded on Day 1 when this has been successfully completed. Overnight, the load will be further reduced on Boiler A to low load. While

the load on Boiler A is decreasing, the load on Boiler B will be increased until stable operation is achieved at high load.

- **Day 2:** NO_x, CO₂, and flue gas flow RATAs will be performed simultaneously on Boiler B at high load operation. As on Day 1, after these tests have been successfully completed, the load on Boiler B will be decreased for the mid range RATA tests. The low range flue gas flow RATA on Boiler A will be performed. When the low range flue gas flow RATA has been successfully completed, testing will be complete on Boiler A.
- **Days 3 and 4:** Like Day 2 for other respective boilers.
- **Day 5:** Finish low range flue gas flow RATA on Boiler D.

3.5 DATA ACQUISITION AND HANDLING SYSTEM

40 CFR 75 also requires testing of the DAHS to verify proper computation of hourly averages for pollutant concentrations, flow rate, pollutant emission rates, and pollutant mass emissions. Also, the missing data substitution procedures and the bias adjustment factor application will be verified. The manufacturer of the DAHS, ESC, has verified through laboratory testing that the data system meets all the requirements for report format, computation accuracy, and missing data substitution. A certification statement will be included in the certification test report.

3.6 TEST REPORT DOCUMENTATION

All pertinent CEMS responses recorded by the DAHS during the testing will be submitted with the test report. All data will be recorded by the DAHS in units consistent with the applicable standard. Each sampling period will be clearly delineated from start to end.

All pertinent supporting reference method data for the RATAs will be included in the test report. This will include all DAHS printouts and chart recordings of the RATA testing periods. QA/QC data will also be submitted. EPA Protocol 1 calibration gas certificates used for the reference method testing will be included in the test report as well.

4. REFERENCE METHODS

The determination of relative accuracy requires comparison of data produced by the installed CEMS with data produced by reference test methods. This section provides descriptions of the reference method equipment and analyzers that will be used to perform the RATAs. The reference methods for each CEM parameter are summarized in Table 4.1. The reference NO_x and CO₂ measurements will be made on a dry basis and converted to a wet basis for comparison with the CEMS.

Table 4.1. Certification test parameters and reference methods

CEM Parameter	EPA Reference Method
Traverse point, sampling point layout	40 CFR 60, Appendix A, Method 1
Flue gas flowrate (for RATA)	40 CFR 60, Appendix A, Method 2
CO ₂ concentration (for RATA and molecular weight)	40 CFR 60, Appendix A, Method 3A
O ₂ concentration (for molecular weight)	40 CFR 60, Appendix A, Method 3A
Moisture (for molecular weight and adjusting reference measurement basis for dry to wet)	40 CFR 60, Appendix A, Method 4
NO _x concentration (for RATA)	40 CFR 60, Appendix A, Method 7E

4.1 REFERENCE METHOD SAMPLING LOCATION AND TRAVERSE POINTS

NO_x, CO₂, O₂, and moisture sampling points will be selected based on the procedures described in 40 CFR 75, Appendix A, Sect. 6.5.6. A stratification test will be performed at each sampling location (refer to Attachment 2) prior to the RATA to identify the appropriate number of measurement points. It is anticipated that a single point at each location will be adequate. Velocity traverse points will be selected based on the procedures in 40 CFR 60, Appendix A, Method 1.

4.2 SAMPLING SYSTEM

An extractive system will be used to transfer flue gas samples from the exhaust duct and to the instrument trailer via Teflon lines in an umbilical cord. The umbilical cord will contain multiple lines that are heated to 250°F to prevent condensation. Other lines will be used for calibration, response time checks, and leak checks. Temperatures will be monitored with Type K thermocouples. A condenser style gas conditioning system will be used to separate the moisture from the flue gas. The conditioning system lowers the temperature of the gas to approximately 35°F and condenses moisture in the sample. Condensate is immediately removed from the sample path, reducing the potential for sample bias. After the sample is dried in the condenser, it will pass through a fine filter to remove any particulate matter remaining in the gas stream. The conditioned flue gas stream will be distributed to the reference analyzers.

4.3 RATA MEASUREMENTS

4.3.1 Nitrogen Oxides

NO_x will be measured using a chemiluminescent analyzer in accordance with 40 CFR 60, Appendix A, Method 7E. The principle of operation of this instrument is a reaction in which ozone (O₃) reacts with nitrogen oxide (NO) to form O₂ and nitrogen dioxide (NO₂). The NO_x analyzer measures the NO_x and NO

concentrations in the stack gas and then calculates the NO₂ concentration by difference. The NO_x analyzer is designed to minimize the effect of common interfering species in the sample gas, such as CO₂, that would potentially reduce the accuracy of the analysis. The reaction chamber, where the NO_x and O₃ combine, operates under a vacuum (typically >27 in. Hg vacuum), and the sample is metered into the reaction chamber in very small quantities. The combination of low chamber pressure and the presence of excess O₃ in relationship to the NO_x present minimizes the quenching of the signal by interfering gases. Measurements made by the NO_x analyzer will be the basis for the RATA.

4.3.2 Carbon Dioxide and Oxygen

CO₂ and O₂ will be measured in accordance with 40 CFR 60, Appendix A, Method 3A. A non-dispersive infrared analyzer will be used to measure CO₂, and a paramagnetic analyzer will be used to measure O₂. Measurements made by the CO₂ analyzer will be the basis for the RATA. Measurements made by the O₂ analyzer will be used to determine the molecular weight of the gas stream that is required to measure flue gas flowrate.

4.3.3 Flue Gas Flowrate

Flue gas velocity and flowrate will be determined using 40 CFR 60, Appendix A, Method 2. An S-type pitot tube and K-type thermocouple will be used to measure the velocity pressure and temperature at points in the duct at the sampling location. The traverse points will be selected based on the procedures in 40 CFR 60, Appendix A, Method 1. Gas density will be determined from temperature and molecular weight. The molecular weight will be based on the concentrations of O₂, CO₂, and moisture. The velocity pressure will be monitored using an inclined manometer or similar device that can measure differential pressure +/- 0.1 in. wc. for differential pressures greater than 1.0 in. wc. and +/- 0.01 in. wc. for pressure below 1.0 in. wc. The flow measurement results will be the basis for the RATA on a wet standard cubic feet per hour basis.

4.3.4 Moisture

Moisture will be measured using the procedure in 40 CFR 60, Appendix A, Method 4. The moisture content of the stack gases will be determined by extracting a sample of flue gas and collecting the moisture in chilled impingers followed by an adsorbent. The collected moisture will be measured gravimetrically, and the dry gas volume will be measured using a gas meter accurate to 2%. The moisture measurements will be performed in conjunction with the RATA concentration and flowrate measurements as described in 40 CFR 75, Appendix A, Sect. 6.5.7. One moisture measurement will be performed per hour during the RATA tests. The duration of each moisture test will be approximately 60 minutes when used to adjust the concentration basis and 30 minutes when used to determine molecular weight. The moisture measurements will be used to adjust the NO_x and CO₂ measurements from a dry to a wet basis and as part of the molecular weight determination.

4.4 CALIBRATION

A linearity calibration check will be performed at the beginning of each test day for each reference method analyzer. Zero and span gases will be introduced through a calibration valve directly into the instrument to establish the calibration curve. A bias check will be performed by introducing zero- and mid-level gases to the end of the probe before and after all runs.

4.5 DATA ACQUISITION

Data from the NO_x and CO₂ reference method analyzers will be logged by a data acquisition system. A printout of the 1-minute averages will be generated, and at the end of each run, the test averages will also be generated. Calibration data will be printed and stored on disk. Data associated with the velocity traverses will be recorded on forms and manually calculated using spreadsheets.

4.6 DATA REDUCTION AND REPORTING

NO_x emissions will be reported as parts per million by volume on a wet basis. CO₂ will be reported as percent by volume, wet basis. Flue gas flow will be reported as standard cubic feet per hour, wet basis. The calculations used for converting concentrations from a dry basis to a wet basis are presented below.

$$NO_{xw} = NO_{xd} \times (1 - B_{ws})$$

where:

NO_{xw} = NO_x concentration, ppm (wet basis),

NO_{xd} = NO_x concentration from reference monitor, ppm (dry basis),

B_{ws} = Moisture fraction in the flue gas.

$$CO_{2w} = CO_{2d} \times (1 - B_{ws})$$

where:

CO_{2w} = CO₂ concentration, ppm (wet basis),

CO_{2d} = CO₂ concentration from reference monitor, ppm (dry basis),

B_{ws} = Moisture fraction in the flue gas.

5. REFERENCE METHOD QUALITY ASSURANCE/ QUALITY CONTROL

Specific QA/QC procedures will be followed during this test program to ensure the production of useful and valid data. The QA/QC checks and procedures described in this section are an integral part of the overall sampling scheme. The data acceptance criteria are summarized in Table 5.1.

Table 5.1. Summary of data acceptance criteria

Criteria	Control limits	Corrective action
Calibration error	$\pm 2\%$ of span	Adjust instrument, recalibrate
Drift between runs (zero and span)	$\pm 3\%$ of span	Data not adjusted for drift
Sampling system bias	$\pm 5\%$ of span	Check heat tracing and/or clean sample line
Response time	Less than 2 minutes	Increase sample flow rate
Line leak check	$< 0.5\% \text{ O}_2$	Locate and repair leak, recheck
NO_2 to NO conversion efficiency	$> 90\%$ conversion where $\text{NO}_2 > 5\%$ of NO_x	Replace converter, recheck
Pitot tube	Verify correct alignment, dimensional ratios	Repair and recalibrate
Thermocouple/thermometer	$\pm 1.5\%$ absolute difference with reference thermometer	Repair or replace
Barometer	Calibrate against mercury barometer	Repair and recalibrate
Dry gas meter calibration factor	Post-test average calibration factor $\pm 5\%$ of pre-test factor	Adjust sample volumes using the factor that gives most conservative value
Analytical balance (top loader)	$\pm 0.1 \text{ g}$ of NBS Class S Weights	Repair balance and recalibrate

The primary control check for precision of the continuous monitors is daily analysis of control standards. The control standards will be used to calibrate the instruments at the beginning and end of each day. The control standards will be introduced upstream of the sample conditioning system for the system bias and drift checks and directly to the sampling manifold for the calibration error checks. EPA Protocol 1 gases will be used.

5.1 LEAK CHECKS

Daily leak checks will be performed. The criterion used for this test will be an O_2 response to a zero gas of less than $0.5\% \text{ O}_2$.

5.2 LINE BIAS CHECKS

Line bias checks verify the integrity of the heat trace and gas conditioning system. A tee fitting at the probe will allow standard gases to be injected through the entire sample system (probe, heat-traced line pumps, and conditioners) prior to the reference method analyzers. A line bias check will be performed at the beginning of the test period to verify that line bias does not exist. The calibration gas will first be sent directly to the appropriate analyzer and the response will be recorded. The same gas will then be sent to the analyzer via the sample line (i.e., through the heat-traced line to the CEM probe and back to the

analyzer), and this response will be compared to the direct response. The line bias response is compared to the direct injection calibration response for the analyzer and must be within 5 % of the span value.

5.3 DRIFT CHECKS

At the beginning and end of each test run, zero- and high-level span gases will be introduced into the instruments. Drift for each test will be determined using the results of the pre-test and post-test calibration checks. Drift must be within 3% of the span value for each test run.

5.4 OTHER QUALITY CONTROL CHECKS

Other QC checks include the following:

- All sampling data will be recorded on standard data forms that will serve as pre-test checklists.
- The number and location of the sampling traverse points will be checked before taking measurements.
- The manometer used to indicate the velocity pressure will be leveled and zeroed.
- The S-type Pitot tube will be visually inspected for damage before and after each run.
- Each leg of the S-type Pitot tube will be leak-checked before and after each run.
- During sampling, the roll and pitch, the axis of the S-type Pitot tube, and the sampling nozzle will be properly maintained.
- Ice will be maintained in the ice bath throughout each run.
- Impingers will be weighed to the nearest 0.1 g before and after sampling.
- The field balance will be checked prior to and after testing against standard weights.
- Any unusual conditions or occurrences will be noted during each run on the appropriate data form.
- The test crew leader will keep a test notebook that will summarize any unusual or noteworthy information regarding all aspects of the testing.